PHD

Long-run marginal cost pricing methodologies in open access electricity networks

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Award date:
2007

Awarding institution:
University of Bath

UNIVERSITY OF
BATH

Long-Run Marginal Cost Pricing Methodologies in Open Access Electricity Networks

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A thesis submitted for the degree of Doctor of Philosophy
University of Bath
Department of Electronic and Electrical Engineering
February 2007

To my deceased grandmother

Abstract

Electricity network pricing methodologies play a key role in determining whether providing network services is economically beneficial to both the utilities and other market participants. There are many pricing methodologies that have been developed since the late 80's, especially for transmission networks. Compared to transmission pricing methods, distribution pricing methods are unsophisticated and pose a significant barrier to embedded generators. Hence, more efficient and executable methodologies are still desirable in open access electricity networks.

This thesis presents a series of new long-run marginal cost (LRMC) pricing methodologies for both transmission and distribution networks, and demonstrates the processes of evaluating and allocating the network asset costs. New reactive power pricing methods, based on the *perpendicular approach* and *arc approach*, have been proposed and demonstrated in these LRMC pricing process.

Compared with other proposed LRMC pricing schemes, the novel long-run marginal cost with utilisation consideration (LRMC-Util%) pricing methodology aims to evaluate the network asset costs based on the usage of the network facilities. It can reflect the future network investment and indicate the future location of network users. The advantages of LRMC-Util% include the ability to reflect the forward looking costs, to distinguish between the costs of siting at different locations, to recognize of the reactive power, and to derive charges for both generation and demand users.

A load-flow-based pricing software package has been developed to implement all the proposed LRMC pricing methodologies. This software can be further employed as a valuable cost analysis tool for transmission and distribution companies.

The methodologies are demonstrated on the IEEE-30 bus test network and a practical distribution test network in the South Wales area of England, UK. An improved and modified methodology based on the concepts developed here was proposed to the Western Power Distribution (WPD) company's network for possible implementation.

Acknowledgements

I would like to express my sincere gratitude to my supervisor Dr. Furong Li for her invaluable guidance and support over the past years.

I thank my colleague Mr. Bless Kuri, who was always gentle and patient to give me help. Also I thank Dr. Marcos Miranda for teaching me a lot in Linux operation system. I am grateful to all the colleagues and academic staff in the Electrical Power & Energy Systems Group for providing an inspired environment. Many thanks to all the support staff in the Department of Electronic and Electrical Engineering for their help on so many occasions. My special thanks go to Mr. Andrew Matthews and Mr. Terry Chau for the proof reading.

I thank the Western Power Distribution (WPD) company for their important support on the network data.

Finally, I would like to make a grateful acknowledgement to my family, especially, my wife Ningyu with the coming baby for all their love, support, inspiration and encouragement to get me over the difficult times.

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List of Abbreviations

AC	Alternating Current
AAEC	Annual Average Embedded Cost
AFCR	Annual Fixed Charge Rate
AMD	Average Maximum Demand
BETTA	British Electricity Trading and Transmission Arrangements
BSUoS	Balancing Services Use of System
CEGB	Central Electric Generating Board
CHP	Combined Heat and Power
DC	Direct Current
DNO	Distribution Network Owner
DISCO	Distribution Company
DRM	Distribution Reinforcement Model
EHV	Extra High Voltage (22KV above in distribution system)
FERC	Federal Energy Regulatory Commission
GB	Great Britain
GENCO	Generation Company
GGDF	Generalized Generation Distribution Factor
GLDF	Generalized Load Distribution Factor
GSDF	Generation Shift Distribution Factor
GWe	Giga Watts electrical
HV	High Voltage (6.6KV or 11KV in distribution system)
ICRP	Investment Cost Related Pricing
ISG	Implementation Steering Group

IEEE	Institute of Electrical and Electronics Engineers
ISO	Independent System Operator
LRMC	Long-Run Marginal Cost
LRMC-Util%	Long-Run Marginal Cost with Utilisation Consideration
LRIC	Long-Run Incremental Cost
LV	Low Voltage (230V in distribution system)
MC	Marginal Cost
NETA	New Electricity Trading Arrangements
NGC	Nation Grid Company
OFGEM	Office of Gas and Electricity Markets
POOLCO	Pool Company
PV	Present Value
REC	Regional Electricity Company
RETAILCO	Retail Company
SMD	Simultaneous Maximum Demand
SRMC	Short-Run Marginal Cost
SRIC	Short-Run Incremental Cost
SVC	Static VAr Compensator
TAWC	Total Annual Wheeling Costs
TNUoS	Transmission Network Use of System
TRANSCO	Transmission Company
UK	Untied Kingdom
WPD	Western Power Distribution

Chapter 1

Introduction

This chapter introduces background information about the electricity network pricing and describes the motivation of this research, which focuses on the price of use of transmission and distribution networks. The main contributions of the study are also summarized, and the layout of this thesis is presented at the end.

1.1 Background

Electricity: " In early use, the distinctive property of 'electric bodies', like amber, glass, etc., i.e., their power when excited by friction to attract light bodies placed near them; also, the state of excitation produced in such bodies by friction. Subsequently the name was given to the cause of this phenomenon and of many others which were discovered to be of common origin with it, e.g. the electric spark, lightning, the galvanic current, etc. ... " Source: The Oxford English Dictionary

In June of 1752, Benjamin Franklin promoted his investigations of electricity and theories through the famous, though extremely dangerous, experiment of flying a kite during a thunderstorm. Nobody could imagine that electricity would become the blood of industry two hundred years later. Life has gone through a complete change due to the electricity supply, and will continue to do so. Since the late 20th century, liberalization has been a major trend in reform of the electrical power industry in many developing and industrialized countries. As the power industries are restructured and decentralized, electricity is becoming a commodity to be bought and sold by generators, suppliers and other traders.

Like the transportation and telecommunication sectors, the electrical power industry is moving from state-owned monopolies to competitive companies. According to the electricity market's hierarchy and architecture, these companies are split into four distinct groups: generation, transmission, distribution, and suppliers (or retailers). Generation companies (GENCOs) produce electricity and maintain power plants. Transmission companies (TRANSCOs) build, operate, and maintain high voltage transmission systems in a certain geographical region, TRANSCOs also provide other services for the overall reliability of the electrical system. Distribution companies (DISCOs) construct and maintain distribution wires, connecting end-use customers to the transmission grid. Such DISCO services include laying cables in roads, and installing meters within properties. Suppliers (RETAILCOs) are the companies who buy electric power and other necessary services, and sell them to customers. While these four types of companies typically function separately, they can be interconnected with each other in the electricity system as shown in Figure 1.1.

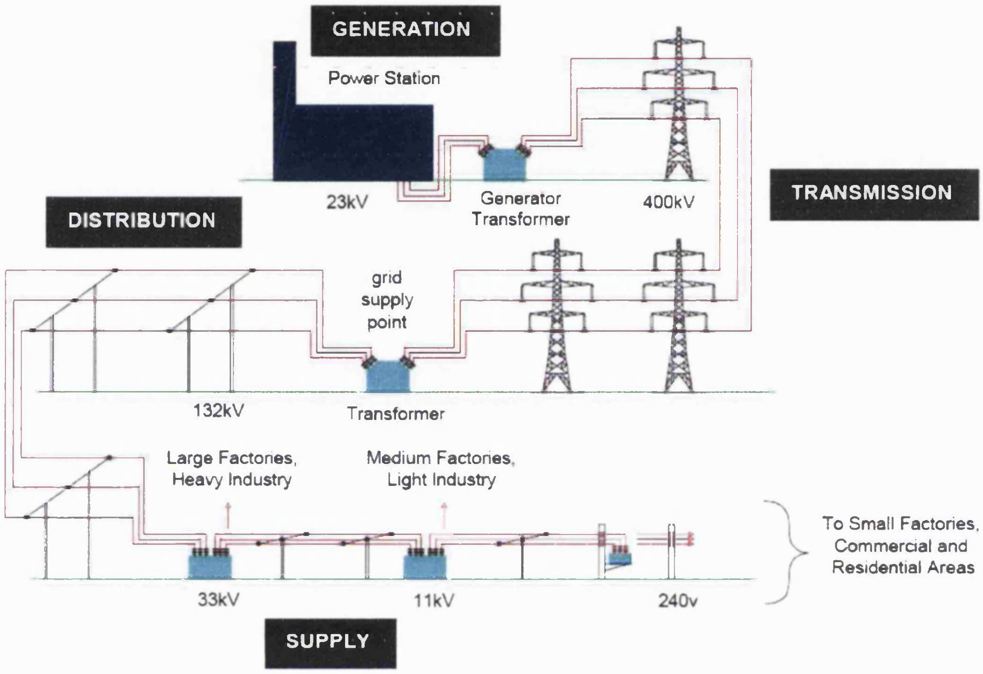


Figure 1.1: An interconnected electricity system [But 2001]

In the electricity market's structure of many countries, such as Chile, Great Britain, Argentina, New Zealand, Australia etc, TRANSCOs provide wholesale transmission capacities and open access for GENCOs. To customers via RETAILCOs at several locations, GENCOs offer electricity that is ultimately delivered through TRANSCOs and DISCOs. It means that the transmission and distribution networks are distinguished from the generation part of the business by their economic characteristics. Especially, the transmission network is usually the single electrical business in a territory where important economies of scale are present. Therefore, competition is not feasible, and natural monopolies develop. In the electricity market, the first challenge is efficiently regulating a monopoly that permits other market participants' competition to take place, which is the role of a regulator. The second challenge is defining a pricing scheme for the transmission services that provides coherent economic incentives for the business to efficiently operate and expand [Rud 1995]. In practice, TRANSCOs and DISCOs recover their investment and operating costs of transmission and distribution network, through connection charges and use of system charges. Developing desirable pricing methodologies for calculating the use of system charges is the main topic of this thesis, which is aim to achieve the objectives defined in the standard conditions of the transmission or distribution licence [Edl 2007, Etl 2007]:

- Facilitating competition in the generation and supply of electricity, and does not restrict, distort, or prevent competition in the transmission or distribution of electricity;
- Reflecting the costs incurred by the licensees in their transmission or distribution businesses;
- Taking account of development in the licensee's transmission or distribution business.

Technically, the use of system charges can be traced back to wheeling rates. The concept of wheeling was introduced by the Federal Energy Regulatory Commission (FERC) in the United States, before the electrical power industry reform. Wheeling is defined as "the transmission of electrical energy from a buyer to a seller, through transmission or distribution lines owed by a third party," and wheeling rates determine payments by the buyers or sellers (or both) to the wheeling utility to compensate the wheeling utility for the network costs incurred [Sch 1985, Car 1986, Rau 1989]. From the view of the movement of electricity from one system to another over transmission facilities of interconnecting systems, wheeling is the third party use of system as an isolated transaction between three parties (buyer, seller, network), and the wheeling rate is to determine the impact and cost of that transaction.

In the competitive electrical power market environment, the use of networks, treated as compositions of various wheeling transactions, can be described as the use of transmission or distribution facilities to transmit the power of and for another entity or entities. The difference between "use of system" and "wheeling" is based on different understanding of the role and the characteristics of electricity networks. Because "use of system charges" and "wheeling rates" have the same aim of creating open access electricity networks, the pricing methodologies can be interchanged between each other.

1.2 Motivation

The transmission system is the most crucial element in electricity market. The secure and efficient operation of the transmission system by TRANSCOs is the key to the efficiency in electricity market. DISCOs are responsible for building and operating their electrical systems, to maintain a certain degree of reliability and availability. DISCOs also have the responsibility of responding to distribution network outages and power quality concerns. TRANSCOs and DISCOs consequently charge GENCOs and/or other DISCOs for their usage of electricity networks. The pricing methodologies play a more and more important role in determining whether or not providing network services is economically beneficial to both the utilities and other market participants. Professionals in power sectors now face a new world, where economic efficiency is replacing technical efficiency as the cornerstone of decision making.

Transmission and distribution prices do not represent a big percentage of the total of electricity bills. For example, in Figure 1.2, the pie chart shows the cost components of household electricity bills in Britain in 2006. About 20% of the total cost is charged to TRANSCOs and DISCOs. Nevertheless, transmission and distribution prices play a vital part in ensuring efficient use of the network, and improving a system's security following the innovative restructuring of the electricity market. Transmission and distribution price should be able to facilitate fair and equitable competition in the trading of energy and services.

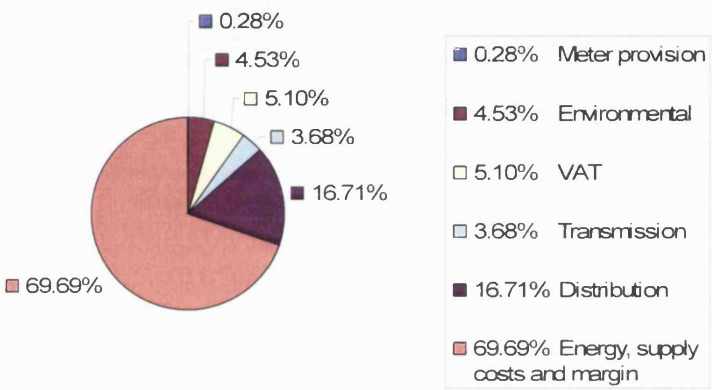


Figure 1.2: Cost components of household electricity bills [Ofg 2006]

According to the trends of electrical market development, transmission and distribution price should be a reasonable economic indicator used by the market to make decisions on resource allocation, system expansion and reinforcement. However, it is important to realize that the pricing of network services, although a technical issue, is not simply an engineering problem. Engineering mainly analyzes the feasibility and cost of providing transmission services, but this is only one of many considerations in the overall process of the pricing of transmission services. Market and political considerations could also play major roles in determining network prices [Shi 1996].

In the UK, the government hopes to increase the contribution of renewable electricity and Combined Heat and Power (CHP) to UK energy supplies. They aim to generate 10% of UK electricity supplied from renewable resources, and to develop 10GWe of installed CHP capacity, all by 2010 [Pos 2001]. Much of this technology will be small-scale and situated close to where its output is used. The electricity output may be less predictable than from another source such as gas, coal-fired or nuclear power stations. The configuration, operation and regulation of current national electricity networks may therefore need modification [Pos 2001]. A distributed electricity system is drafted in Figure 1.3. The Office of Gas and Electricity Markets (OFGEM), the regulator of electricity in the UK, is currently evaluating the enduring appropriateness of the transmission charging arrangement for distributed generation. At the same time, distribution charging arrangements pose a significant financial barrier to new smaller-scale generation, because new entrants must pay the full up-front connection costs. OFGEM is holding a Structure of Electricity Distribution Charges Implementation Steering Group (ISG) [Ofg 2007] simultaneously to determine how regulation could help to develop embedded generation. A long term solution is developing within the industry during 2005 and 2006.

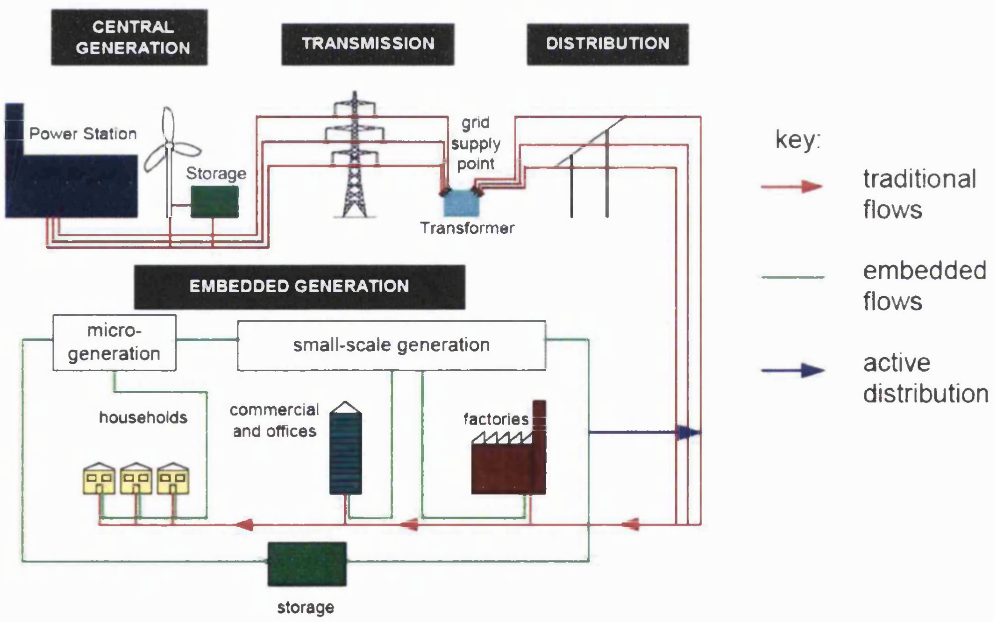


Figure 1.3: A distributed electricity system [But 2001]

Transmission and distribution prices mainly include connection charges and use of system charges. Connection charges are applied to new customers who intend to connect to the system. They are based on the asset costs of additional network facilities and the energy policies from the government. Once the tariffs of the connection charges are authorized, they are then fixed for a certain period. Use of system charges are derived from pricing methodologies, depending on the degree of usage of the system for existing customers. There are many difficulties and emphases in the network pricing methodologies. Firstly, there is no appropriate tool and data for evaluating the economic impact of different pricing methodologies. Secondly, although use of system charges provide a lot of useful system information, they have not influenced the market operation even for the future energy mix. Thirdly, considering the various objectives and constraints of the electrical power system, the pricing methodologies are based on limited experience and political considerations. These should be replaced by a more economic approach.

Because of the various factors involved in the use of electricity networks charges, pricing methodologies have been emphasized from both the electrical power industry and academic researchers. Many researches have been developing pricing methodologies for different purposes. However, more efficient and executable methodologies are still desirable for both industry and academia, which will also be useful for many developed and developing countries in their electrical power industry evolution.

1.3 Contribution

The main purpose of this research is to introduce a new series of long-run marginal cost pricing methodologies for both transmission and distribution networks, and to demonstrate the approaches in evaluating the network asset cost, and allocating the cost.

There are three major contributions in this research. Firstly, the long-run marginal cost based on DC power flow (LRMC-DC), similar with the Investment Cost Related Pricing (ICRP) model of the National Gird Company (NGC) in the UK, is formulated and applied on a practical distribution test system. LRMC-DC demonstrates the advantages of cost reflectivity and locational price signal. Secondly, with new developed reactive power pricing methodologies, the proposed long-run marginal cost-AC (LRMC-AC) is capable of allocating cost to reactive power. Thirdly, a novel long-run marginal cost with network utilisation consideration (LRMC-Util%) is being further developed and implemented, which is based on the concept of University of Bath model [Li 2005b, Wpd 2006c]. The advantages of LRMC-Util% include the ability to reflect forward looking costs, to distinguish the costs at different locations, to recognize the reactive power, and to balance the treatment between generation and demand.

In this thesis, a comprehensive review of transmission and distribution pricing methodologies is included. Most existing pricing methodologies are formulated and explained. The pricing models using by transmission and distribution companies in the UK are emphasized.

A load-flow-based charging software package has been developed to implement the different pricing paradigms, including proposed LRMC-AC and LRMC-Util%. The software can be further employed as a valuable cost analysis tool for transmission and distribution companies.

The methodologies are demonstrated on the IEEE-30 bus standard test network and practical distribution test networks in the South Wales area of England. An improved and modified methodology based on the concept of LRMC-Util% was proposed to the Western Power Distribution (WPD) company's network for possible implementation.

1.4 Thesis Layout

There are seven chapters in this thesis. Chapter 1 is an introduction which covers the motivation and main achievements of this research work. Chapter 2 defines the meaning of long term marginal cost pricing methodologies in open access electricity networks, and the different pricing mechanisms under various market operations which shows the big picture behind this research. Chapter 3 and 4 are the literature reviews of network pricing methodologies. Chapter 3 explains the pricing process of transmission networks, and reviews existing transmission network pricing methodologies. Chapter 4 introduces the regulation of distribution network pricing and explains the existing distribution network pricing methodologies. Chapter 5 demonstrates the traditional long-run marginal cost based on DC load flow (LRMC-DC) firstly. With the allocation of reactive power price, LRMC-AC is formulated and tested. Chapter 6 presents and implements the long-run marginal cost with network utilisation consideration (LRMC-Util%). The advantages of LRMC-Util% compared with LRMC-AC are analyzed by different case studies. Chapter 7 includes the final conclusion and future work.

Chapter 2

Network Pricing in the Market Environment

Nations all over the world have committed to, or currently are in the process of, introducing more competition into their electrical power sectors. Moving from monopolies to competitive markets, network pricing is becoming a debated issue for network participants. Great Britain's (GB) system is demonstrated as an example of a typical electricity innovation pioneer. After the costs components in various categories of wheeling transactions are introduced, and the concept of long-run marginal cost is illustrated. The different existing pricing strategies are summarized into three paradigms in the market environment. Finally, the objectives of network pricing are presented.

2.1 From Monopolies to Market

2.1.1 Centralized and Decentralized

Prior to privatization, the electrical power industry was a government monopoly. A single, vertically integrated utility was the only electricity provider in its service territory. Traditionally, the main provider was owned by a national or regional government. In this centralized framework, the whole process of energy generation, transmission, distribution and supply was highly regulated and controlled. It also meant that GENCOs, TRANSCOs, DISCOs, and RETAILCOs, as introduced in the background of Chapter 1, were either integrated into a multifunction company or a group of government holding companies. Because utilities were allowed to pass costs on to the customers through exclusive tariffs, there was little incentive to reduce costs, or to make investments with due consideration of risk. Serious efforts to calculate the cost of providing the electricity network services separately from the overall cost of the supplying electricity were unnecessary.

The growth of the generation and information technologies and the stimulation of the competitive global economy, spurred many trends in the electrical power industry, including the privatization of nationally owned systems, the deregulation of privately owned systems, and the internationalization of national systems. Essentially, GENCOs, TRANSCOs, DISCOs, and RETAILCOs are running as four distinct parts. TRANSCOs and DISCOs provide and sell market participants non-discriminatory access to their unbundled network service. It is also called network "open access". The underlying theme of these changes is the replacement of a centralized monopoly with decentralized competition.

In a decentralized market environment, an independent system operator (ISO) is a necessary market entity. The key roles of the system operator are balancing the real-time market, and maintaining the system security in the operations of the power market. Depending on the ISO's objective and authority, power balancing during a certain period may be included in the ISO's operation. The ISO with power balancing is an independent, non-government and non-profit entity that ensures a competitive market by running an auction for electricity trades. The ISO calculates the market clearing price based on the highest bid in the market.

2.1.2 Pool and Bilateral Contracts

In order to achieve electricity market goals, two basic models for the market structure have been considered.

1. Pool model

In a pool model, there are no direct transactions between producers and customers. All trading is done via a pool company (POOLCO), which is defined as a centralized marketplace that clears the market for buyers and sellers. Electric power sellers and buyers submit bids to the pool for the amounts of power they are willing to trade in the market. On one hand, sellers compete for the right to supply energy to the pool, not to specific customers. If a seller bids too high, it may not be able to sell. On the other hand, buyers compete for their right to buy energy not from specific generators but from the pool. If a buyer bids too low, it may not be able to buy. An ISO within a POOLCO would implement the economic dispatch and produce a single price for electricity, giving participants a clear signal for consumption and investment decisions.

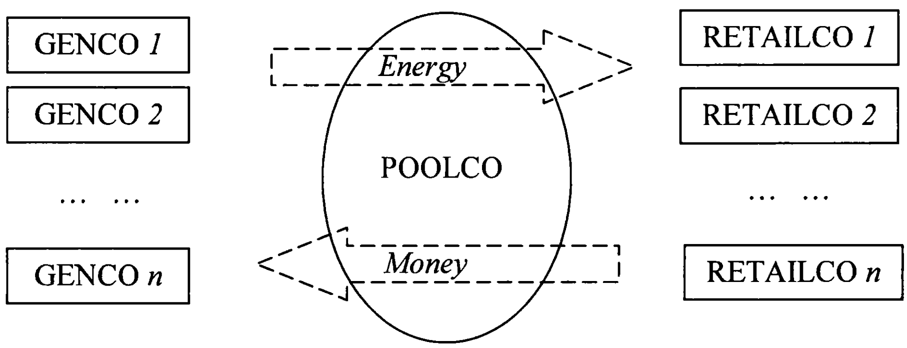


Figure 2.1: Pool model

2. Bilateral Contracts Model

Bilateral contracts are negotiable agreements on delivery and receipt of power between two traders. These contracts set the terms and conditions of agreements independently of the ISO. Each contract is based on one or many network transactions between GENCO and RETAILCO. In this model, however, the ISO would verify that a sufficient transmission capacity exists to complete the transactions and maintain transmission security. The bilateral contract model is very flexible as trading parties specify their desired contractual terms.

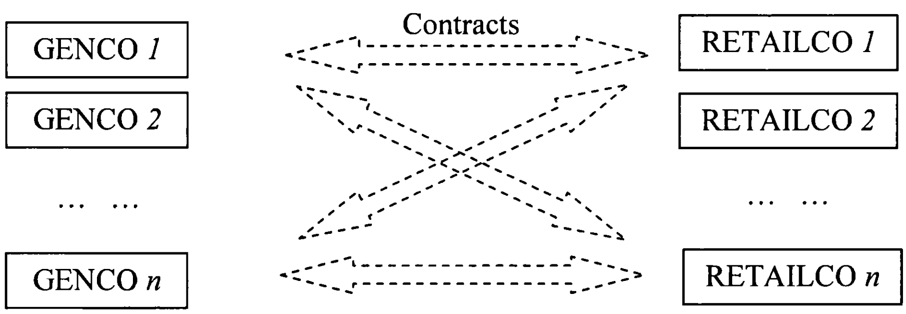


Figure 2.2: Bilateral contracts model

In both models, it is necessary to employ appropriate network pricing methodologies for transmission and distribution network owners. GENCOs and/or RETAILCOs need pay network owners for use of their system in the market environment.

2.1.3 Market Structure and Network Pricing in GB

Great Britain is one of pioneers in electricity market reform. It is also a typical example of developing market structure and network pricing. This section will describe how the electricity market set up and where the network prices come from in GB.

In Great Britain, before privatization, most electricity was generated by the Central Electricity Generating Board (CEGB), a government-owned nationalised industry. It also operated the national grid transmission system. The CEGB had a statutory obligation to plan and produce electricity to meet demand. The Electricity Council set prices at levels designed to meet financial targets set by the government. In England and Wales, twelve local area boards, which were also government-owned monopolies, ran distribution and supply activities.

The 1990s saw significant changes in the electricity industry of England and Wales, in response to the requirements of industry participants, customers and the regulator- the Office of Gas and Electricity Markets (OFGEM). The fossil fuel generation within the CEGB was privatized as National Power and PowerGen. Including Scottish Power and Hydro-Electric, there were in total four major generating companies. The nuclear plants were transferred to the government-owned Nuclear Electric and Scottish Nuclear, which have since been restructured into two companies, one of which has been privatised (British Energy). Control of the transmission system went to the National Grid Company (NGC), which was initially owned at the time of privatization by the twelve Regional Electricity Companies

(RECs). The power industry has significantly changed since the Electricity Pool of England and Wales was created on 31st March 1990 [Poo 2006]. As an arrangement between generators and suppliers, the Pool provided the wholesale market mechanism for trading electricity. The Pool itself did not buy or sell electricity, and those trading in the Pool did so within a defined set of rules. Participation in the market was through membership of the Pool, and done so under the Pooling and Settlement Agreement.

On 27th March 2001, the New Electricity Trading Arrangements (NETA) for England and Wales went into effect [Net 2007]. Replacing the previous Pool arrangement, the NETA allowed market players to trade electricity up to a day ahead of the requirement for physical delivery. National Grid Company (NGC) operated as the system owner and system operator for England and Wales, managing the high voltage (275KV and 400 KV) transmission system, and also providing all the technical and operational services normally demanded by the system to ensure its integrity, such as load forecasting, system security and stability, frequency control, and reactive power control. NGC acted at both a physical and a financial level through the balancing mechanism, selecting bids and offers for incremental or decremented supply of electricity, in order to achieve physical balance between generation and demand.

The British Electricity Trading and Transmission Arrangements (BETTA) Programme was launched in April 2005, which extends NETA to create a competitive Great Britain (GB, include England, Wales and Scotland) wide electricity market [Bet 2007]. It also proposed that the GB system operator should recover the total costs of the transmission system on a GB basis. Consequently, National Grid Company (NGC) extended the role of system operator for the whole GB and remained as the system owner for England and Wales. The transmission systems in Scotland are owned by the Scottish Power and Scottish & Southern Energy. Figure 2.3 shows the market structure of BETTA.

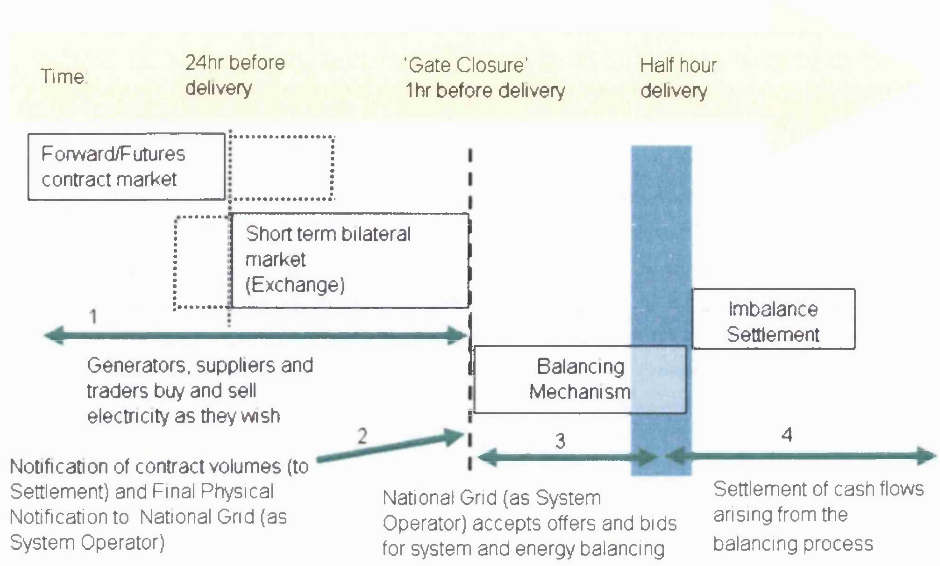


Figure 2.3: Overview of BETTA market structure [Sys 2006]

Under either the NETA or BETTA program, the National Gird Company (NGC) is both the system owner and the system operator. The NGC charges for the usage of the transmission network by the generator companies, suppliers and other license holders. As the system owner, the NGC issues the statement of the connection charging methodology [Ngc 2006]. This statement explains how to charge the users' connection fee. It defines the boundary between infrastructure and connection assets, the calculation of charges for providing those assets and the manner of sharing assets between the different users at the same site. As the system owner and operator, NGC issues the statement of the use of system charging methodology [Ngc 2006]. This statement covers both the Transmission Network Use of System (TNUoS) and the Balancing Services Use of System (BSUoS) methodology.

The TNUoS charges reflect the cost of installing, operating, and maintaining the transmission system for the transmission owner activity function of the transmission business. The Investment Cost Related Pricing (ICRP) was introduced by NGC in 1993/4, and is applied as a DC Load Flow (DCLF) ICRP based transport model from

April 2004. The DCLF ICRP transport model calculates the marginal costs of investment in the transmission system, which would be required as a consequence of an increase in demand or generation at each connection point. After the BETTA went into effect, TNUoS charges are extended to Scotland with introducing demand and generation tariff zones. In Scotland, with the role of system operator shift from Scottish TRANSCOs to NGC, Scottish GENCOs and RETAILORs are joined the wholesale electrical power market of GB. Therefore, the justification of the transmission charge methodology attracts more and more attention from generation companies and suppliers.

At the DISCOs' side, there are seven Distribution Network Owners (DNOs) that operate in fourteen service zones as shown in Figure 2.4.

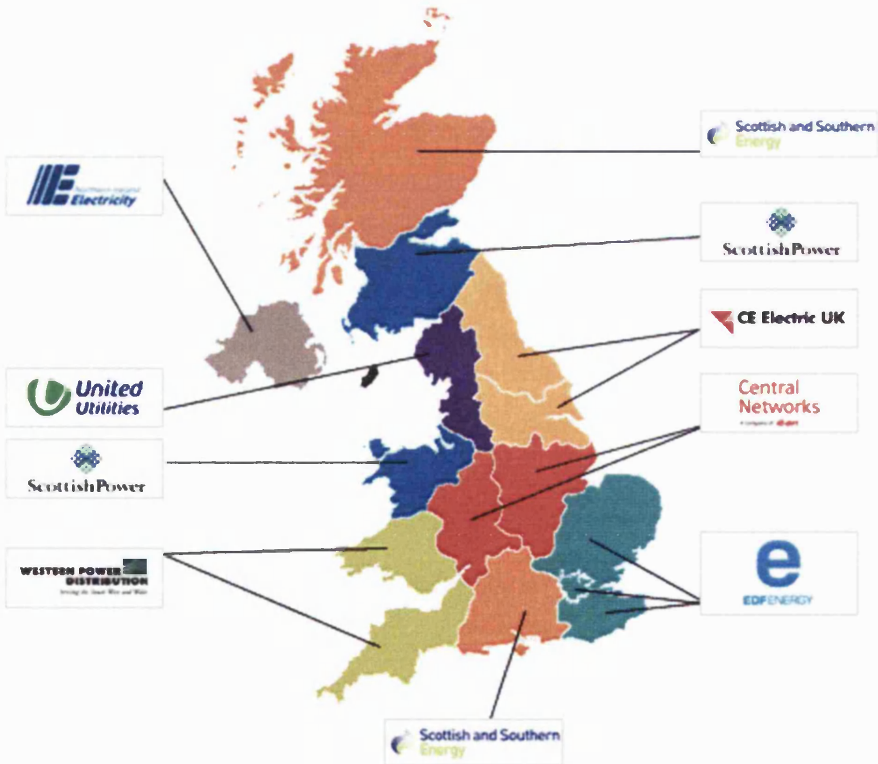


Figure 2.4: DNOs' location [Sys 2006]

Each DNO has a statement of the connection charging methodology, a statement of use of system charging methodology, and a statement of metering and data services charging. The statements of use of system charging methodologies of DNOs are taking the same responsibility as NGC's.

Overall, in the electrical power industry reform of Great Britain, the electrical power system has changed from government owned monopolies to a pool model, followed by a transition to a bilateral contracts model, which is in effect at the time of this writing.

2.2 Cost Components in Wheeling Transactions

The extended use of an electricity network is a composite of various types of wheeling transactions. Use of network charge is produced with the successful wheeling transaction. In this section, fundamental concepts and terms regarding the cost components of providing wheeling transactions services are introduced and explained. Then the concept of long-run marginal cost (LRMC) is illustrated in detail. Note that all the terms explained are based on the decentralized market structure. Some of the terms may have different meanings under different market structures.

2.2.1 Cost Components

The major components of the cost related to wheeling transactions are [Shi 1991]:

1. Existing System Cost

The existing system cost of a wheeling transaction is the allocated cost of existing network facilities used by that wheeling transaction. The cost of the existing system is the cost associated with the investment made in construction and the expenses incurred in maintaining the system. For example, the existing system cost includes the network asset cost, and the Operation and Maintenance (O&M) cost. It is important to note that a wheeling transaction does not involve any new costs relating to the use of existing transmission facilities, because these facilities have been built already. But it incurs the expense to operate and maintain the existing network hardware for TRANSCOs and DISCOs. So the major issues are who should bear the cost of the existing network, and how the cost should be allocated amongst the wheeling transactions.

2. Operating Cost

The operating cost is the fuel cost that the utilities incurs in order to accommodate the wheeling transaction. The operating cost are due to generation re-dispatch and rescheduling, which results from the operation of the POOLCO in the Pool operation market model, or is mainly referred to the balancing services for ISOs in bilateral contracts market model. Generation re-dispatch is caused by meeting the system operating constraints, such as the transmission line flow and bus voltage limits. Generation rescheduling is impacted by factors such as the start-up time of generation and the spinning reserve requirements. The operating cost is mainly affected by the characteristic of the generation units of the generation companies.

3. Opportunity Cost

The opportunity cost corresponds to the unrealized benefits due to operating constraints that are caused by the wheeling transaction. The cost of lost opportunities is incurred through two mechanisms. One is the unrealized savings in fuel cost if the generation companies cannot bring in cheaper energy due to transmission system operating constraints. Another is the unrealized contribution to the cost of potential, but unrealized, firm transactions due to transmission system operating constraints. GENCOs cannot achieve the conceivable benefit, so it is also called "shortage cost." According to the obligation of TRANSCOs that ensure the potential transaction, it is also called "congestion cost" from the TRANSCOs' point of view.

4. Reinforcement Cost

The reinforcement cost refers to capital cost of new transmission facilities, or the facility upgrades needed to cope with changes in the pattern of demand. It also includes the cost of planned network reinforcements that are deferred by the wheeling transaction. Although the concept of the reinforcement cost is straightforward, the evaluation of the reinforcement cost is extremely difficult according to the uncertainty of network operating constraints. The reinforcement cost is charged by TRANSCOs and DISCOs and absorbed by GENCOs and RETAILCOs.

Because the cost of the existing system includes voltage control, reactive power compensation, frequency regulation, flow regulation, loading following service, etc., the existing system cost is the largest component of the overall cost of the transmission transaction. Compared with the existing system cost, the other three aforementioned components (operating cost, opportunity cost and reinforcement cost) are directly caused by the transaction. They are commonly called the incremental cost of the wheeling transaction, referring to the entire cost of a new transaction [Shi 1991].

Other terms are used in the industry to refer to the components of the cost of a transmission transaction. These terms include "short-run incremental cost," which refers to operating cost and opportunity cost, "long-run incremental cost," which refers to operating cost, opportunity cost and reinforcement cost, and "embedded cost," which refers to a portion of the existing system cost.

2.2.2 Categories of Wheeling Transaction

The following categories may be used to identify the type of wheeling transaction [Shi 1991, Lee 2001]:

1. Firm and Non-Firm

"Firm" transactions are those that are not subject to discretionary interruptions. Firm wheeling transactions are also known as reserved transactions, because they entail the reservation of capacity on network facilities to meet transaction needs. Firm wheeling transactions are the results of contractual agreements between GENCOs and RETAILCOs, so they are also called contractual transactions.

"Non-firm" transactions are those that may be reduced or increased. Reducible transactions are ongoing transactions that may be curtailed at the utilities' discretion. Increasable transactions take place when the transmission capacity becomes available in specific areas of the systems at short notice, and so they are also called "as available" transactions. Non-firm wheeling transactions are derived from unbalanced power after the firm transactions. It is vital for the ISO to schedule non-firm transactions to secure the real-time electricity market.

2. Short-Run and Long-Run

Traditionally, a long-run or long-term transaction takes place over one or several years. The duration of a long-run transaction is usually long enough to allow the building of new transmission facilities. Long-run transmission transactions are the results of contractual agreements between the wheeling customers. A short-run or short-term transaction may be from as short as a few hours to as long as one or two years, and are not generally associated with transmission reinforcements. Short-run transactions may be provided either under a bilateral contract or as part of a transmission arrangement.

In the competitive market environment, the time interval is too indistinct to distinguish between long-run and short-run. Instead, it is clearer to classify by the different cost components involved, which are shown in Table 2.1.

Table 2.1: Cost components for each transmission transaction [shi 1991]

Transaction Type	Firm	Non-Firm	
		Reducible	**Increasable**
Short-term	Operating cost Opportunity cost Existing system cost	Operating cost Opportunity cost	Operating cost
Long-term	Operating cost Existing system cost Reinforcement cost	Operating cost Opportunity cost	N/A

From the economic considerations, associated with the basic inputs of labour and capital, are the notions of fixed and variable cost, which can be summed together to make the total cost. Fixed cost is a common term brought in to define the short-run or long-run. Fixed costs are fixed during a specific period. Although a cost may be fixed during a short period, such as a month, it could vary for a longer period, such as a year. Dependent on the flexibility of cost and technology, the short-run and long-run are shown in Table 2.2.

Table 2.2: Short-run or long-run [Rot 2003]

Time	Cost	Technology
Very short run	All cost are fixed	Fixed
Short run	Some cost are fixed	Fixed
Long run	No cost are fixed	Fixed
Very long run	No cost are fixed	Not fixed

2.2.3 Long-Run Marginal Cost (LRMC)

Marginal cost (MC) is originally a basic principle of economic regulation. The MIT Dictionary of Modern Economic defines marginal cost as "the extra cost of producing an extra unit of output." Paul Samuelson defines marginal cost more cautiously as the "cost of producing one extra unit more or less" [Sto 2002]. The "or less" is important. The assumption behind this definition is that producing one more unit of output would cost exactly as much as producing one less unit would save. This is true for the continuous marginal cost curve of textbook economics, as shown in Figure 2.5. To discuss the marginal cost of a discontinuous supply curve, which is the case in the electricity industry, the definition must be extended to include the points of discontinuity, where the cost to produce an extra unit is distinctly greater than the savings from producing one less. The Marginal costs are derived from the left-hand marginal cost (MC_{LH}) and right-hand marginal cost (MC_{RH}). Marginal cost range is defined as the range of values between and including MC_{LH} and MC_{RH}, as exemplified in Figure 2.6.

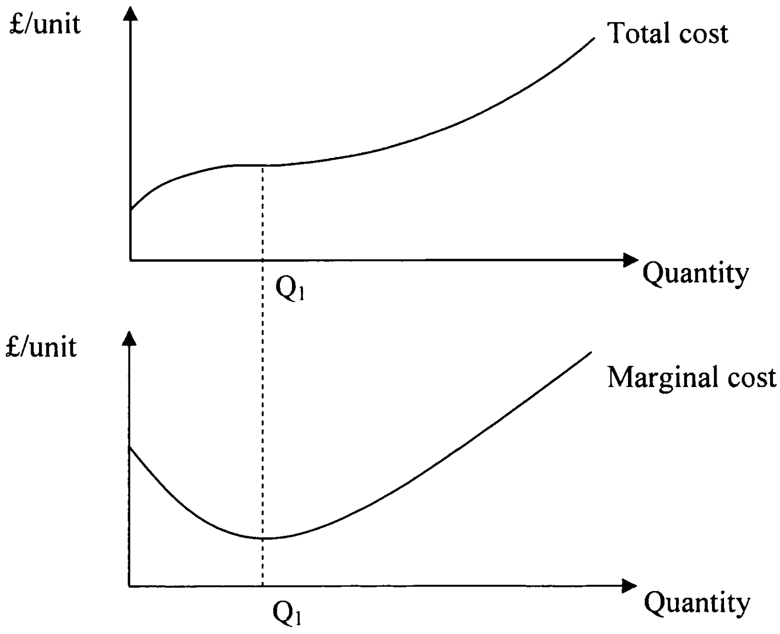


Figure 2.5: Continuous MC curve

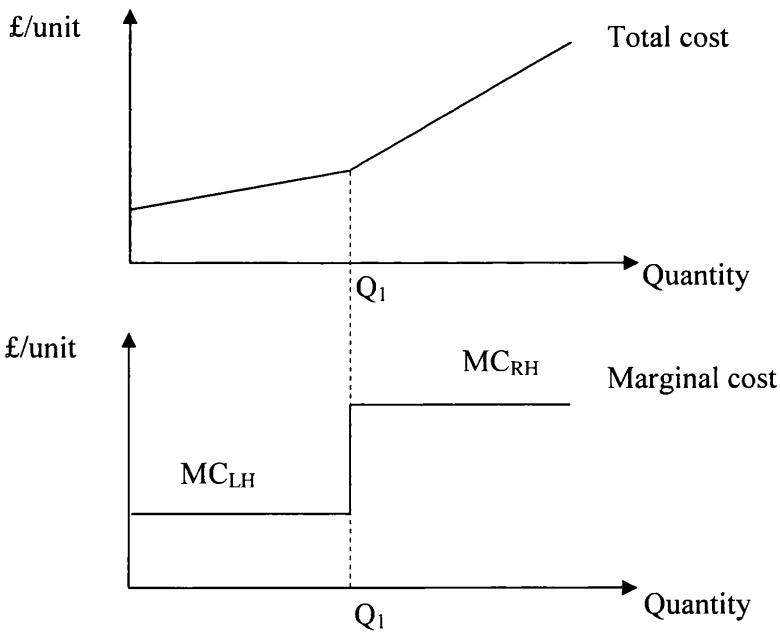


Figure 2.6: Discontinuous MC curve

In an efficient market with competitive equilibrium, the market price is fixed. All price takers have shares of the market, but they will not have the ability to change the market price and profit from doing so. In the short-run, a competitive producer sets the output to a level at which the marginal cost equals the market price, whether or not that is the competitive price. This maximizes profit. In the long-run, investment is involved and plays an important part. Following the definition from economics, profit equals revenue minus total cost, where total cost includes a normal, risk-adjusted, return on investment. The normal economic profit level is zero. However, business defines a normal return on equity to be profit.

To make the concept of marginal cost more clear in electricity market, TRANSCOs and DISCOs are price takers from GENCOs and DISCOs, and are competitive producers of transmission and distribution services. Their use of system price is under control by the government regulator. For instance, the allowance for capital and operating expenditure of TRANSCOs and DISCOs is set out by OFGEM in the price control period, which is five years in the U.K. [Ofg 2007a, Ofg 2007b]. Because the consumer wants a low price, the regulator has the role of making the competition provide the lowest possible price. Competition does not guarantee the lowest possible price at any point in time. Nevertheless, it guarantees that price takers will just cover the long-run total costs, and no more. Together these mean that the long-run costs of investment are minimized, and producers are paid only enough to cover their capital cost. So the long-run marginal cost is good for consumers.

There are many discussions about the details of determining the electricity system marginal cost in an integrated market [Ber 1992, Sto 2002]. But this research is focused on the marginal cost in an electricity network. In the following sections of this thesis, marginal cost only refers to the marginal cost of an electricity network, not the whole electricity system. So long-run marginal cost pricing is based on the cost of accommodating a marginal increase (of one unit, for instance) in the transacted power. It is also approximately the saving from producing one less unit. In this thesis, these are assumed to be so close together that no distinction is necessary, and this is typically the case.

2.3 Network Pricing Strategies

According to the four cost components of providing the wheeling transaction, there are many network pricing mechanisms that were developed to cover the overall cost. In consideration of the largest proportion of existing system cost, the key issues of the network pricing mechanism are who uses the existing network, and how the cost should be allocated among the wheeling transaction. An efficient network pricing mechanism should recover network costs by allocating the costs to electricity network users in a proper way. A network pricing paradigm is the overall process of translating network cost into overall use of system charges with a detailed network pricing mechanism. There are three paradigms introduced below [Kov 1994, Shi 1996]:

2.3.1 Embedded Paradigm

In this paradigm, both the existing system costs and the new costs of system operation and expansion, regardless of their cause, are first summed up ("rolled-in") into a single number [Hap 1994, Shi 1996]. This cost is then allocated among various users of the system according to their "extent of use" of the transmission system. Since this paradigm ignores the scarcity of network resources caused by a new transmission transaction, the embedded transmission pricing paradigm cannot reflect the economical inefficiency.

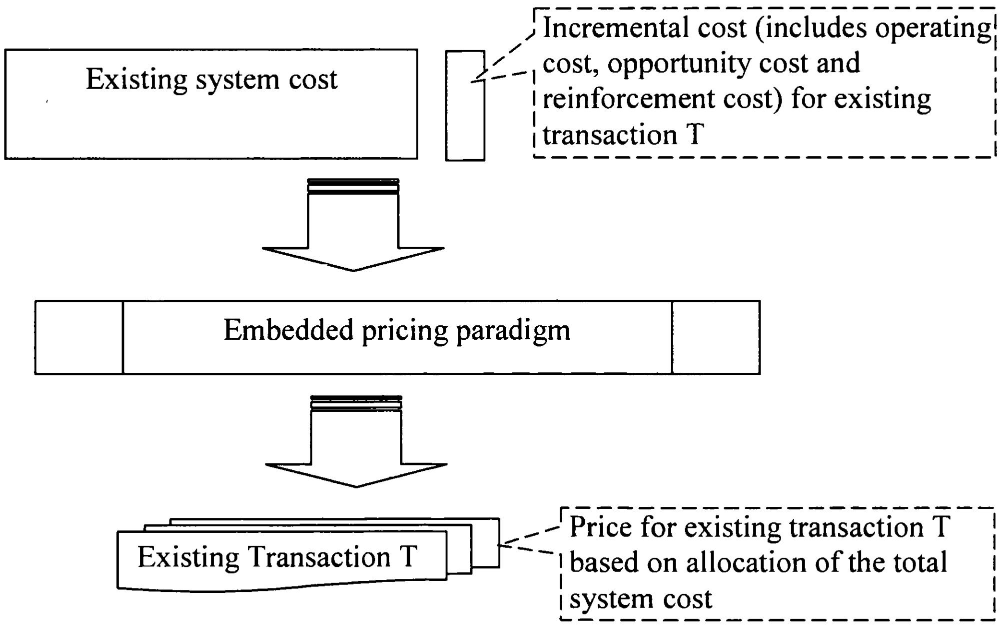


Figure 2.7: Embedded Pricing Paradigm

2.3.2 Incremental Paradigm

According to this paradigm, only the new transmission costs caused by new transmission customers are considered when evaluating transmission charges for these customers. The incremental transmission pricing paradigm requires one or more transmission transactions to be considered as a margin [Shi 1996]. Therefore, the paradigm can produce a completely irrelevant result. Since the ranking of a transaction is normally based on historical or political reasons, many subjective arguments could arise.

Incremental cost can be defined as the revenue requirements needed to pay for any new facilities that are specifically attributed to the transmission service customer.

Incremental cost of a transaction is evaluated by comparing the transmission system costs with, and without, the entire transaction. However, the marginal approach would multiply the cost for a unit of an additional transaction by the size of that transaction.

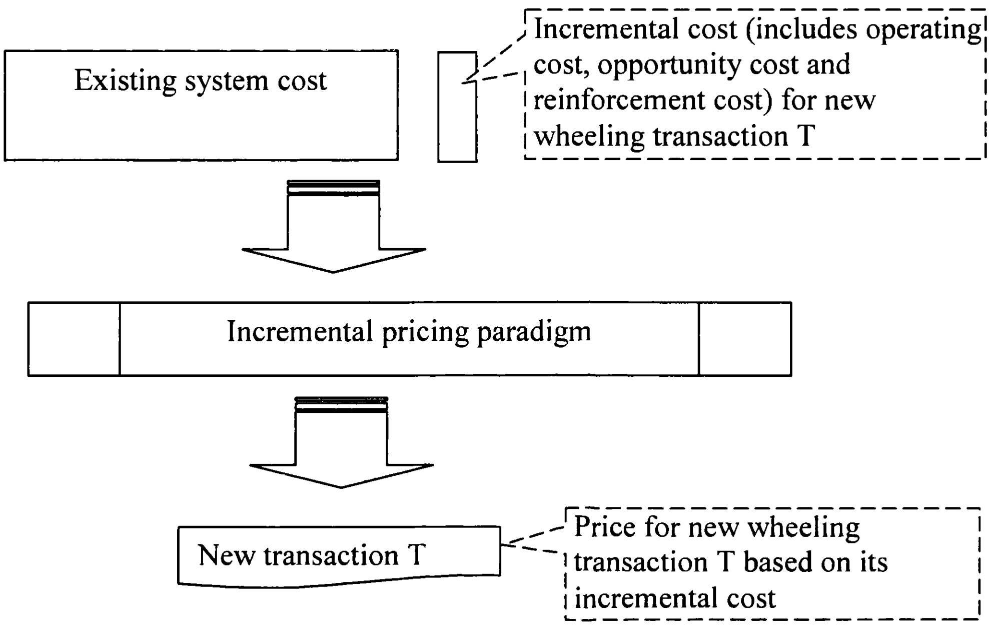


Figure 2.8: Incremental pricing paradigm

2.3.3 Composite Embedded/Incremental Paradigm

This pricing paradigm includes both the existing system cost and the incremental cost of a transmission transaction in evaluating overall transmission prices [Shi 1996]. In general, the price of a transmission service is based on the sum total of the embedded and incremental costs of providing the service. Figure 2.9 shows the basic concept of this paradigm.

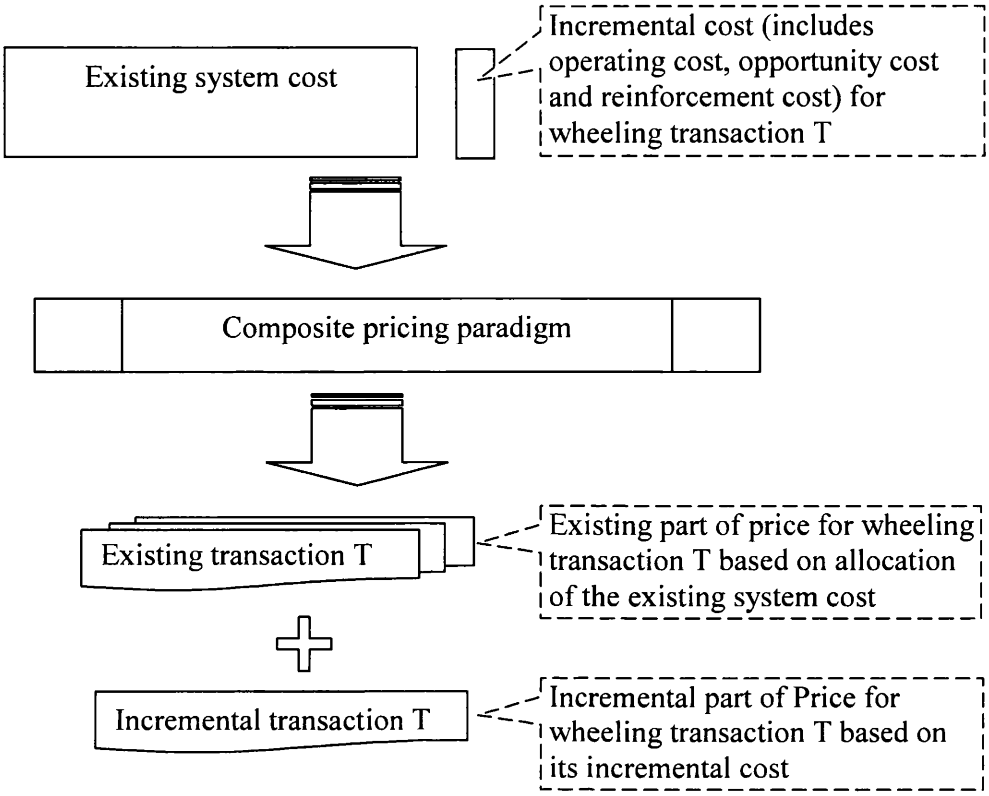


Figure 2.9: Composite pricing paradigm

2.4 Objectives of Network Pricing Methodologies

The fundamental principle of any network pricing methodologies is to allocate all or part of the existing and new cost of a network system to the network users. However, since the operation of the electricity market are based on the policies and directives set by the respective government in each country, the network pricing methodologies should adopt similar objectives, including cost reflectivity, encouraging efficient use, transparency, simplicity, predictability, and encouraging investment.

Cost reflectivity: Network pricing should reflect the costs incurred by TRANSCOs or DISCOs in their transmission or distribution businesses [Edl 2007, Etl 2007]. Under the conditions of the transmission or distribution licence, the pricing strategies should be driven by the network asset costs. Revenue obtained from the tariffs charged for the usage of the network services should be adequate to recover all the expense incurred in investment, operation and maintenance, and a regulated level of profit. It has the same meaning as "recover allowed revenue".

Encouraging efficient use: The price should provide incentives to encourage efficient use of the electricity network. Efficient usage of the network can be attributed to technical efficiency which minimizes losses. Efficient use also means the price should give a locational indication for customers, such as embedded generators.

Transparency: The pricing schemes should be able to transmit the right economic signals to all network participants. It should be fair and justifiable.

Simplicity: The pricing schemes should be as simple as they can. Although the implementation of pricing methodology may be not so easy, the pricing schemes should be easily understandable.

Predictability: The pricing schemes should produce a tariff following a correct economic prediction. It is very important for network participants to forecast the possible future cost.

Encouraging investment: The pricing scheme and the dividends paid to various network owners should provide an incentive for investment in new infrastructure as and when necessary.

Cost reflectivity is an essential driver of the pricing schemes. Encouraging efficient use, transparency, simplicity, and predictability are expected to benefit GENCOs and RETAILCOs. Encouraging investment will bring advantage to the TRANSCOs and DISCOs. Besides all of the above, there are more potential benefits, such as independence, facilitation of competition, etc.

Chapter 3

Pricing Methodologies of Transmission Networks

This chapter reviews the existing pricing methodologies of transmission networks. The methodologies are divided into two categories of embedded or incremental/marginal pricing paradigms. The embedded pricing paradigms are divided further into non-flow-based and flow-based pricing methods. The advantage and disadvantage of each methodology follows after the explanation. Finally, in the UK, the use of system charging methodology of the National Gird Company (NGC) is explained as a typical example of the long-run marginal cost (LRMC) pricing scheme.

3.1 Chapter Introduction

TRANSCOs play an important role in maintaining the security of the transmission network, supporting large quantity and long distance wheeling transactions crossing regions, states, or even nations. Simultaneously, the transmission network is where conventional GENCOs compete to supply RETAILCOs in a markets environment. Thus, transmission pricing should be a reasonable economic indicator when making decisions on system expansion, reinforcement, and resource allocation [Sha 2002]. Since wheeling is introduced as the first step towards the open access transmission network, many pricing methods are developed following each stage of electricity market reform. Therefore, pricing methodologies of transmission networks are more comprehensive than those of distribution networks.

Essentially, the process of transmission network pricing includes three major processes.

1. Cost evaluation: Because cost reflectivity is a main driver for network pricing schemes, the first process has to be evaluating the transmission network asset costs. According to the different cost allocation methods, the network asset cost may include both the existing network cost and network expansion cost, or both fixed cost and variable cost, or the direct and indirect oncost.
2. Cost allocation: Based on the evaluated network asset costs, the different methodologies are employed to allocate the cost to existing and new network customers. Generally, the embedded pricing methods refer to usage based cost allocation methods. The incremental/marginal pricing methods are related to the network investment and expansion costs.
3. Revenue reconciliation: Scaling or modifying the price to set up the final tariffs, which aim to meet the final company allowed revenue.

Because the cost calculated from first two steps may under recover the capital cost, there is the need for a supplement of revenue reconciliation. Economists offer different options for allocating this reconciliation among the network users. They may take the following forms for the power system [Rud 1995]:

1. Ramsey pricing scheme, which is based on customer demand elasticity.
2. Uniform uplift, which is allocated as a lump sum to different users.
3. Proportional to allocated cost.
4. Base on independent measure, such as, installed capacity.
5. Base on other use of system pricing methodologies.

As indicated, the process of revenue reconciliation is mainly an economic problem, normally not included in individual network pricing methodology. So the cost evaluation and cost allocation are the most distinguishing characteristics between different pricing methods.

Following the network pricing paradigms introduced in Section 2.3 of Chapter 2, pricing methodologies of transmission networks can be categorized into embedded cost pricing and incremental/marginal cost pricing paradigms. The embedded pricing methods include non-flow-based and flow-based pricing methods. The existing pricing methodologies of transmission network are comprehensively reviewed in the rest of this chapter. Note that there is no single best solution for the universal use of transmission network charging. In practice, each country or each restructuring electricity market has chosen a method that is based on the particular characteristics of its network.

3.2 Non-Flow-Based Pricing Methods

Non-flow-based pricing methods mean they do not need power flow calculation, and include the postage stamp method and contract path method. They are the most common and unsophisticated approaches. Regardless of the influence of power flow, they can hardly encourage the efficient use of the system in electricity markets.

3.2.1 Postage Stamp Method

Postage stamp methodology is one of the earliest transmission network pricing methodologies. This method assumes that the entire transmission system is used in wheeling transactions, irrespective of the actual transmission facilities that carry the wheeling services [Hap 1994]. A simplified algorithm is listed as below [Lee 2001]:

1. Calculate the net plant (NP_l) cost of each line.

$$NP_l = BC_l - DR_l \tag{3.1}$$

Where,

BC_l: the book cost for each transmission line,

DR_l: the depreciation reserve for each transmission line.

2. Calculate the annual fixed charge rate ($AFCR$) for each year of the study period, which is obtained from the company's cost data and includes long term debt, preferred stock, common equity, weighted cost of capital per year, operating and maintenance costs, taxes, administrative and general expenses, and insurance.

3. Calculate the annual average embedded costs ($AAEC$).

$$AAEC = AFCR \cdot \sum_{l=1}^{L} \frac{NP_l}{PeakDemand + WheelingIncrement} \tag{3.2}$$

Where,

$AAEC$: the annual average embedded costs (£/MW),

L: the total number of transmission lines.

4. Calculate the total annual wheeling costs ($TAWC$).

$$TAWC = AAFC \cdot WheelingIncrement \tag{3.3}$$

Where,

$TAWC$:the total annual wheeling costs (£/MW).

This method allocates charges to a transmission user based on an average embedded cost, and the magnitude of the user's transacted power. The cost of wheeling as determined by postage stamp method is independent of the transmission distance and network configuration [Sha 2002, Shi 1996]. Traditionally, it is used by electrical utilities to allocate the fixed transmission cost amongst the users of firm transmission services. It does not require power flow calculation, so it is very straightforward for all wheeling utilities to implement. However, if energy is transmitted across several transmission systems, it can suffer a pancaking problem, which means accumulating a high wheeling cost.

3.2.2 Contract Path Method

Overcoming the pancaking problem, Contract path methodology is based on the assumption that transmission transaction can flow along specified and artificial electrical paths [Hap 1994]. The contract path refers to the specified geographical distance between the generators and consumers, regardless of the physical paths along electrons flow. After the artificial contract paths are defined, transmission prices will then be assigned using a postage-stamp rate, which are determined either individually for each of the transmission systems, or on the average for the entire grid [Sha 2002]. A simplified algorithm is listed as below [Lee 2001]:

1. Calculate the net plant (NP) cost and annual fixed charge rate ($AFCR$) as for the postage stamp methodology in Section 3.2.1, shown in Equation 3.1 and Equation 3.2.

2. Determine the lowest MW capacity of facilities along the specified path.

3. Calculate the annual average embedded costs (*AAEC*).

$$AAEC = AFCR \cdot \sum_{l=1}^{K} \frac{NP_{,l}}{lowestMWofPath} \tag{3.4}$$

Where,

K: the total number of transmission lines in path.

4. Calculate the total annual wheeling costs (*TAWC*).

$$TAWC = AAEC \cdot WheelingIncrement \tag{3.5}$$

The contract path methodology ignores the facilities, which lie along this assumed path. With the additional consideration of the distance between generators and consumers, the contract path method is otherwise just like the postage stamp methodology, and is also used by electrical utilities to allocate the fixed transmission cost among the users of firm transmission service. However, the method does not reflect actual flows through the transmission network, that include loop and parallel path flows.

3.3 Flow-Based Pricing Methods

With power flow calculation, flow-based pricing methods are more sophisticated than non-flow-based pricing methods. The boundary flow method replaces the users' transacted power in the postage stamp method by the real power flow cross the predefined boundary, which is the first flow-based method. MW-mile method evaluates the unit cost of individual lines by the capacity and distance, making it a milestone in transmission pricing methodology. After the development of various enhanced MW-miles methods, the process of cost evaluation in pricing methodologies reached a mature period. Distribution factors methods, AC power flow methods, and tracing methods focus on the allocation of each network asset cost. Chronologically, they are described in detail below:

3.3.1 Boundary Flow Method

The boundary flow method incorporates the impact of a sale on the transmission system to the gross change in real power flow, either on a line basis or on a net interchange basis [Hap 1994]. Following the load level represented in the power flows at peak load or at other appropriate load levels, there are two power flows executed, with or without the transaction, for every year. So these two power flows correspond to either individual boundary lines or net interchange real power flow. Using all boundary line flow or net interchange flow to replace the magnitude of the user's transacted power in the postage stamp method, it is called boundary flow method or power allocation method [Kov 1994]. This methodology is very close to the postage stamp methodology in Section 3.3.1, and a simplified algorithm is listed as below [Lee 2001]:

1. Calculate the net plant (*NP*) cost of each line, the annual fixed charge rate (*AFCR*) for each year of the study period, and the annual average embedded costs (*AAEC*). They are as same as the postage stamp methodology in Section 3.2.1.

2. Calculate the total annual wheeling costs (*TAWC*).

$$TAWC = AAEC \cdot \left(\frac{1}{2} \cdot \sum_{l=1}^{L} \left| \Delta MW_l \right| \right) \tag{3.6}$$

Or

$$TAWC = AAEC \cdot \left(\frac{1}{2} \cdot \sum_{k=1}^{K} \Delta NetInterchange_k \right) \tag{3.7}$$

Where,

L: the total number of boundary lines,

K: the total number of net interchanged lines.

Each interchange consists of a group of boundary lines that connect the wheeling company with one specific neighbouring company. All the boundary lines may contain circular components of MW flows, which do not visible in the net interchanged lines. For example, there are two boundary lines connected to the area A. If there is a circular flow within a wheeling transaction as shown in Figure 3.1, the MW flows for boundary lines and net interchanged lines can be calculated respectively as below:

$$\sum_{l=1}^{L} |\Delta MW_l| = 10 + 10 = 20$$

$$\sum_{k=1}^{K} \Delta NetInterchange_k = 10 - 10 = 0$$

So it is clear to see the difference between Equation 3.6 and Equation 3.7.

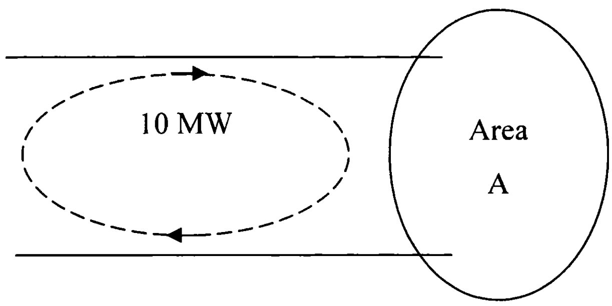


Figure 3.1: Circular flow's example

Again, this methodology is also used to allocate the fixed transmission cost amongst the users of firm transmission service.

3.3.2 MW-Mile Method

The MW-mile method is a milestone in transmission pricing methodology. In this methodology, the transmission network capacity used for a transaction is a function of the magnitude, the path and the distance travelled by the transacted power. Hence, this methodology is called "MW-mile methodology" [Shi 1989]. Because it considers the changes in MW flows and transmission line length, it is also known as "Line-By-Line methodology" [Hap 1994, Sha 2002]. Given a transaction with an actual point and specified variations in generation and load, the MW-mile methodology calculates the maximum transaction related power flow on every transmission line, using DC power flow and linear programming algorithms. The maximum transaction related flow on every line is multiplied by the line length and a factor reflecting the cost per unit capacity of the line [Shi 1989]. The detailed algorithm is demonstrated as below:

1. Determine the unit cost per MW capacity (W_l) of the transmission line l,

$$W_l = \frac{H_l}{Q_l} \tag{3.8}$$

Where,

H_l: the unit cost of the transmission line, which is a function of numerous factors including the line voltage class, location, date of construction, the conductors used (£/KM),

Q_l: the transmission line capacity, which is dependent on its voltage class and other factors such as the size and the type of conductors used (MW).

2. Calculate the transmission cost related to the transaction t,

$$MWMILE_t = \sum_{l \in K} \left(W_l \cdot MW_{t,l} \cdot L_l \right) \tag{3.9}$$

Where,

$MWMILE_l$: total transmission network cost related to transaction t (£),

$MW_{t,l}$: line flow over the transmission line l for transaction t (MW),

L_l: length of transmission line l (KM),

K: set of lines.

3. Repeat the process for every transaction by considering only the generation and loads associated with that transaction.

4. The share of the total transmission network capacity cost allocated to the transaction t can be calculated according to the following formula:

$$TC_t = TC \cdot \frac{MWMILE_t}{\sum_{t \in T} MWMILE_t} = TC \cdot \frac{\sum_{l \in K} \left(W_l \cdot MW_{t,l} \cdot L_l\right)}{\sum_{t \in T} \sum_{l \in K} \left(W_l \cdot MW_{t,l} \cdot L_l\right)} \tag{3.10}$$

Where,

TC_t: cost allocated to transaction t (£),

TC: total transmission network capacity cost (£),

$MWMILE_t$: total transmission network cost related to transaction t (£),

T: set of transactions.

This methodology was firstly introduced by Dariush Shirnohammadi in 1989, and applied to two categories of transactions. The first category specifies the locations and fixed values for the generation and load, and there is a power balance for the transaction. The other category identifies by the locations of generation and load and the range of variation in the generation and load [Shi 1989]. The MW-Mile method is the first pricing method proposed for the recovery of fixed transmission costs based on the actual use of the transmission network. Equation 3.10 also can be rewritten as:

$$TC_t = \sum_{l \in K} \left(C_l \cdot \frac{MW_{t,l}}{\sum_{t \in T} MW_{t,l}} \right) \tag{3.11}$$

Where,

$C_l = TC \cdot \dfrac{W_l \cdot L_l}{\sum_{l \in T} \left(W_l \cdot L_l\right)}$: is called embedded cost of line l.

The MW-mile methodology takes into account parallel power flow, and eliminates the problem of previous transmission pricing methods. It is intuitively logical and a conceptually straightforward approach to implement. Although it needs a recalculation of power flows in all lines if network configuration changes, this method is still favoured by TRANSCOs because it directly encourages the efficient use of the transmission network.

3.3.3 Enhanced MW-Mile Methods

There are many other methodologies that have been investigated that are based on the MW-mile method, and modify the real power flow (MW) by another format. So they are generally called enhanced MW-mile methods.

1. Modulus MW-Mile Method

It is also called the usage method, and assumes that all agents have to pay for the actual capacity use and for the additional reserve [Kov 1994]. A simple way to ensure the recovery of all embedded costs, based on the MW-mile method while retaining its advantages, is to replace the circuit capacities by the sum of absolute power flow and the additional reserve capacity [Sha 2002]. A simple formulation is shown in Equation 3.12.

$$TC_t = \sum_{l \in K} \left(C_l \cdot \frac{|MW_{t,l}|}{\sum_{t \in T} |MW_{t,l}|} \right) \qquad (3.12)$$

The reserve capacity may be due to the need of system meeting reliability, stability and security criteria, or due to inefficient system design. However, there is no incentive for the agent to alleviate the circuit load, improve the system performance and postpone transmission investment [Lim 1996].

To compare with other MW-mile methods, an example is set to demonstrate the modulus MW-mile method. In Figure 3.2, it assumes that the transaction 2 is made by a counter flow.

A ———————————— B

$\rightarrow$

Net flow:	A $\rightarrow$ B	100MW
including:		
Transaction 1:	A $\rightarrow$ B	110MW
Transaction 2:	A $\leftarrow$ B	10MW

Figure 3.2: Counter flow's example

Using Equation 3.12,

$$TC_t = \sum_{l \in K} \left(C_l \cdot \frac{|MW_{t,l}|}{\sum_{t \in T} |MW_{t,l}|} \right) = C_l \cdot \frac{110}{110+10} + C_l \cdot \frac{10}{110+10}$$

So the final cost of each transaction by the modulus MW-mile method is:

wheeling cost for transaction 1 : $C_l \cdot \dfrac{110}{110+10}$

wheeling cost for transaction 2 : $C_l \cdot \dfrac{10}{110+10}$

The counter flow is charged as same as net flow.

2. Zero Counter-Flow Method

Counter flow is the flow component contributed by a particular transaction that goes in the opposite direction of the net flow. In the zero counter-flow method, only the agents that use the circuit in the same direction of the net flow, pay in proportion to their contributions to the total positive flow [Lim 1996, Pan 2000].

$$TC_t = \sum_{l \in K} \left(C_l \cdot \frac{MW_{tK,l}}{\sum_{tK \in TK} MW_{tK,l}} \right) \quad (3.13)$$

Where,

TK: set of transactions with positive flows on the circuit K.

Using Equation 3.13, the same example shown in Figure 3.2 is taken:

$$TC_t = \sum_{l \in K} \left(C_l \cdot \frac{MW_{tK,l}}{\sum_{tK \in TK} MW_{tK,l}} \right) = C_l \cdot \frac{100}{100}$$

So the final cost of each transaction by the zero counter-flow method is:

wheeling cost for transaction 1 : $C_l \cdot \frac{100}{100}$

wheeling cost for transaction 2 : 0

The null cost for transaction 2 explains the name of "zero counter-flow" method directly.

This method assumes that the net flow reduction is beneficial, but it is not true if there is already an "excess" installed capacity. Moreover, for a lightly loaded circuit, there is a discontinuity on the charges when the net flow changes the direction [Lim 1996].

3. Dominant Flow Method

The dominant flow method is a combination of the modulus method and zero counter-flow method [Lim 1995, Lim 1996]. The circuit capacity is divided into two components called base capacity and additional capacity.

$$TC_t = \sum_{l \in K} \left(C_{lA} \cdot \frac{MW_{tK,l}}{\sum_{tK \in TK} MW_{tK,l}} + C_{lB} \cdot \frac{|MW_{t,l}|}{\sum_{t \in T} |MW_{t,l}|} \right) \quad (3.14)$$

Where,

$C_{lA} = C_l \cdot \dfrac{f_l}{Q_l}$: embedded cost of line l of base capacity,

$C_{lB} = C_l \cdot \dfrac{Q_l - f_l}{Q_l}$: embedded cost of line l of additional capacity,

f_l: total flow of circuit l,

Q_l: capacity of circuit l,

Using Equation 3.14, the same example shown in Figure 3.2 is taken:

$$TC_t = \sum_{l \in K}\left(C_{lA} \cdot \frac{MW_{tK,l}}{\sum\limits_{tK \in TK} MW_{tK,l}} + C_{lB} \cdot \frac{|MW_{t,l}|}{\sum\limits_{t \in T} |MW_{t,l}|} \right)$$

$$= C_{lA} \cdot \frac{100}{100} + C_{lB} \cdot \frac{110}{110+10} + C_{lB} \cdot \frac{10}{110+10}$$

So the final cost of each transaction is:

Wheeling cost for transaction 1 : $C_{lA} \cdot \dfrac{100}{100} + C_{lB} \cdot \dfrac{110}{110+10}$

Wheeling cost for transaction 2 : $C_{lB} \cdot \dfrac{10}{110+10}$

Using dominant flow method, the participant who uses the system in the counter flow direction receives an incentive in the terms of smaller costs. From the above example, when the circuit is near to fully loaded, the C_{lB} is near to zero. It means that the incentive increases as the circuit gets more loaded. This can encourage reducing the circuit loading condition to postpone the expansion plan. Therefore, the dominant flow method can take the advantages from both the modulus MW-mile and the zero counter-flow methods, and represent counter flow in a practical way. But, it is not easy for transmission companies to arrange payments to users.

3.3.4 Distribution Factors Methods

In general, generation distribution factors are calculated based on line load flow, and have been used in the domain of power system security and contingency analysis [Ng 1981, Rud 1995], because they can approximate the relationship between the generation and load values on transmission line flow. Distribution factors based on DC power flows can be used for the evaluation of the transmission capacity usage under various open access structures. In recent years, the application of distribution factors have been assigned to allocate the transmission cost amongst the different users, i.e., to transaction-related net power injections which are called Generation Shift Distribution Factors (GSDFs), to generators only which are called Generalized Generation Distribution Factors (GGDFs), or to loads only which are called Generalized Load Distribution Factors (GLDFs).

1. Generation Shift Distribution Factors (GSDFs)

GSDFs, or A factors, provide line flow changes due to a change in generation, which are used to identify the maximum transaction-related flow for bounded generation and load injections [Ng 1981, Rud 1995, Sha 2002].

$$\Delta F_{l-k} = A_{l-k,i} \cdot \Delta G_i \tag{3.15}$$

$$\Delta G_i = -\Delta G_r \tag{3.16}$$

Where,

ΔF_{l-k}: change in flow in line l-k which from bus l to bus k,

$A_{l-k,i}$: a factor of a line joining buses l and k, due to shift of generation on generator i,

ΔG_i: change in generation of generator i, excluding the reference generator r,

ΔG_r: change in generation of reference generator r,

$A_{l\text{-}k,i}$: is calculated using the definition of a reactance matrix and the DC load flow, which can be calculated as below:

$$A_{l-k,i} = \frac{\Delta F_{l-k}}{\Delta G_i} = \frac{\Delta I_{l-k}}{\Delta I_i} \tag{3.17}$$

$$\Delta I_{l-k} = \frac{\Delta V_{l-k}}{X_{l-k}} = \frac{X_{li} - X_{ki}}{X_{l-k}} \cdot \Delta I_i \tag{3.18}$$

Where,

ΔI_{l-k}: change in current in line *l-k*, due to shift of generation from ΔG_i to ΔG_r,

ΔI_i: change in injection current into bus *i*,

ΔV_{l-k}: change in voltage in line *l-k*, due to shift of generation from ΔG_i to ΔG_r,

X_{li}, X_{ki}: elements of the reactance matrix, which is from the reverse of the admittance matrix without the reference bus,

$X_{l\text{-}k}$: reactance in line *l-k*.

Therefore,

$$A_{l-k,i} = \frac{X_{li} - X_{ki}}{X_{l-k}} \tag{3.19}$$

The values of GSDFs are dependent on the network configuration and the selection of reference bus, while they are independent of the total generation of the system and the distribution of generation or load. Using GSDFs, the incremental cost of transmission network by generators can be measured.

2. Generalized Generation Distribution Factors (GGDFs)

GGDFs, or D factors, determine the impact of each generator to line flows [Ng 1981, Rud 1995, Sha 2002]. Based on the A factors from GSDFs, GGDFs are defined as:

$$F_{l-k} = \sum_{i=1}^{N} \left(D_{l-k,i} \cdot G_i\right) \tag{3.20}$$

$$D_{l-k,i} = D_{l-k,r} + A_{l-k,i} \tag{3.21}$$

$$D_{l-k,r} = \frac{F_{l-k}^{0} - \sum_{i=1,i\neq r}^{N}\left(A_{l-k,j} \cdot G_i\right)}{\sum_{i=1}^{N} G_i} \tag{3.22}$$

Where:

N: numbers of generator,

F_{l-k}: total real power flow in line *l-k* after shift,

$D_{l-k,i}$: GGDF of a line *l-k* corresponding to the generation at bus *i*,

G_i: total generation at bus *i*,

$D_{l-k,r}$: GGDF of a line *l-k*, due to the generation at reference bus *r*,

F_{l-k}^{0}: original flow in line *l-k* before shift.

GGDFs depend on line parameters and system configuration, and not on the choice of reference bus. GGDFs can measure the total use of transmission network facilities produced by generator injections. Using GGDF, each network line cost can be allocated to individual generators.

3. Generalized Load Distribution Factors (GLDFs)

GLDFs, or C factors, are very similar to GGDFs [Rud 1995, Sha 2002]. GGDFs determine the contribution of each load to line flows.

$$F_{l-k} = \sum_{i=1}^{N}\left(C_{l-k,j} \cdot L_j\right) \tag{3.23}$$

$$C_{l-k,j} = C_{l-k,r} + A_{l-k,j} \tag{3.24}$$

$$C_{l-k,r} = \frac{F_{l-k}^{0} - \sum_{j=1,j\neq r}^{N}\left(A_{l-k,j} \cdot L_j\right)}{\sum_{j=1}^{N} L_j} \tag{3.25}$$

Where:

F_{l-k}: total real power flow in line *l-k* after shift,

$C_{l\text{-}k,j}$: GLDF of a line $l\text{-}k$ corresponding to the generation at bus r,

L_j: Total demand at bus j,

$C_{l\text{-}k,r}$: GLDF of a line $l\text{-}k$, due to the generation at reference bus r,

$F_{l\text{-}k}^{0}$: original flow in line $l\text{-}k$ before shift.

GLDFs also depend on line parameters, system configuration and not on the choice of reference bus. GLDFs can measure the total use of transmission network facilities by loads which are treated as negative injection. Using GLDF, each network line cost can be allocated to individual loads.

3.3.5 AC Flow Sensitivity Indices Methods

The AC flow sensitivity indices method use the same logic as the distribution factors methods, but is based on AC power flow calculation instead of DC power flow. Two indices are introduced below, including line utilisation factor for real power pricing, and reactive power adjustment factor for reactive power pricing.

Similar to the distribution factors, line utilisation factors were introduced to evaluate the sensitivity of the flow on a line with respect to power generation at all buses [Par 1998, Cha 2002]. The relationship between the incremental line flow and the incremental power generation at any bus via line utilisation factors is given as follows:

$$\Delta P_{ij} = u_1^{ij} \cdot \Delta P_{G,1} + u_2^{ij} \cdot \Delta P_{G,2} + \cdots + u_{n-1}^{ij} \cdot \Delta P_{G,n-1} + u_n^{ij} \cdot \Delta P_{G,n} \qquad (3.26)$$

The numerical values of line utilisation factors can be calculated using standard AC power flow Jacobian matrix with some minor simplifications [Par 1998].

The concept of a reactive power adjustment factor was introduced as a measure of the impact of unit MVA load change, or a transaction on the total generation reactive power output [Hao 1997]. The author mentioned that reactive power losses are typically about ten times greater than active power losses due to the inductive nature of transmission line. The formulation of a reactive power adjustment factor (RPAF) is shown below, involving only the sensitivity indices of network reactive power losses of the active and reactive injections, together with appropriate scaling factors.

$$RPAF = \Delta q_i + \alpha \cdot \frac{\partial Q_{loss}}{\partial q_i} \cdot \varepsilon_i \cdot \Delta q_i + \beta \cdot \frac{\partial Q_{loss}}{\partial p_i} \cdot \sigma_i \cdot \Delta p_i \qquad (3.27)$$

Where,

Q_{loss}: the transmission network reactive power losses,

Δq_i, Δp_i: the unit reactive and active power load at bus i,

α, β: scaling factors that can be used to reconcile the difference between the total reactive power losses and the total incremental reactive power losses,

ε_i, σ_i: scaling factors for ensuring that the load increments at bus i are consistent with specified power factors.

Based on the line utilisation factor and the reactive power adjustment factor, the AC flow sensitivity indices methods can bring more detailed real and reactive cost information to study the impact of wheeling transaction.

3.3.6 Transaction Assessment Methods

Transaction assessment methods are also based on the full AC power flow solution, including power flow decomposition methods and multi-transactions assessment methods.

Accurate decomposition of power flow into flows contributed by individual transactions is essential for cost-based pricing of transmission services. The power flow decomposition method proposes an approach to decompose network flows into components associated with each particular transaction, and an interaction component, based on the superposition of all transactions on the network [Zob 1997a, Zob 1997b]. It can then calculate the power flows and imbalance on the network subject to each given economic transaction using distributed slack bus. The power imbalance caused by a particular transaction can be compensated for by allocating the net system power imbalance amongst different embedded generating units according to the participation factors. The transmission system related fixed cost component is recovered from all transactions based on percentage utilisation of the transmission system equipment. Then, the operating costs for a given transaction can be computed as the sum of the costs incurred for compensating the power imbalance.

A power flow based on multi-transaction assessment methodology was introduced [Bar 1999], which is based on comparing the difference between power flow simulations, including the difference between base case (no transactions) and operating case (all transactions), and only transaction *t* case, and all transactions except *t* case. The methodology determines for each transaction the following: the flow path of the transaction (both real and reactive power flow changes caused by a transaction); generator reactive power support from each area/utility; and real power loss support from each area/utility. It is then determined how much should be allocated to this transaction.

All transaction assessment methods are a very precise way to assign the cost to network users, but they require more detailed network cost information.

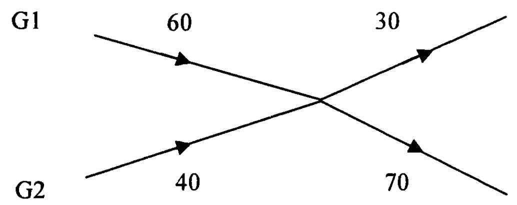
3.3.7 Tracing Methods

Tracing methodologies determine the contribution of transmission users to transmission usage, and are generally based on the proportional sharing principle.

Each transmission asset cost can then be shared between different users in different proportion. Unlike the distribution factors methods, tracing methods are not restricted by the network configuration.

1. Bialek's Tracing Method

This method assesses the magnitude of the real and reactive power output from a particular generator goes to a particular load. It also assesses the contributions of individual generators (or loads) to individual line flows [Bia 1996, Bia 1998, Bia 2000].



$$30 = \underbrace{\frac{60}{60+40} \cdot 30}_{\text{from G1}} + \underbrace{\frac{40}{60+40} \cdot 30}_{\text{from G2}}$$

$$70 = \underbrace{\frac{60}{60+40} \cdot 70}_{\text{from G1}} + \underbrace{\frac{40}{60+40} \cdot 70}_{\text{from G2}}$$

Figure 3.3: Proportional sharing principle

In Bialek's tracing method, it is assumed that nodal inflows are shared proportionally among nodal outflows (Figure 3.1). Before executing Bialek's tracing method, it is necessary to get the result of the power flow which is a basic and vital calculation of the power system analysis. The algorithm for tracing the flow of electricity is derived into two versions. One is the upstream-looking algorithm, which looks at the nodal balance of inflows; the other is the downstream-looking algorithm which finds the nodal balance of outflow. The following shows how the upstream-looking algorithm works. The gross demand is defined as the sum of a particular load and its allocated part of the total transmission loss. The topological distribution factor refers to the k^{th} generator's contribution to line *i-j* flow.

$$P_{ij}^{g} = \frac{P_{ij}^{g}}{P_{i}^{g}} \cdot P_{i}^{g} = \frac{P_{ij}^{g}}{P_{i}^{g}} \cdot \sum_{k=1}^{n} \left[\mathbf{A}_{\mathbf{u}}^{-1}\right]_{ik} \cdot P_{GK} = \sum_{k=1}^{n} D_{ij,k}^{g} \cdot P_{GK}\ ,\ j \in \alpha_{i}^{d} \tag{3.28}$$

Where,

$$P_{i}^{g} = \sum_{j \in \varepsilon_{i}^{u}} \left|P_{ij}^{g}\right| + P_{Gi}\ ,\ i=1,2,\ldots,n \tag{3.29}$$

$$\left[\mathbf{A}_{\mathbf{u}}\right]_{ij} = \begin{cases} 1 & i=j \\ -\left|P_{ij}\right| / P_{j} & j \in \alpha_{i}^{u} \\ 0 & otherwise \end{cases} \tag{3.30}$$

$$D_{ij}^{g} = \frac{P_{ij}^{g} \cdot \left[\mathbf{A}_{\mathbf{u}}^{-1}\right]_{ik}}{P_{i}^{g}} \approx \frac{P_{ij} \cdot \left[\mathbf{A}_{\mathbf{u}}^{-1}\right]_{ik}}{P_{i}} \tag{3.31}$$

And

P_{ij}^{g}:	Unknown gross line flow in line *i-j*,
P_{i}^{g}:	Unknown gross nodal power flow through node *i*,
$\mathbf{A}_{\mathbf{u}}$:	Upstream distribution matrix,
P_{GK}:	Generation in node *K*,
α_{i}^{d} :	Set of nodes supplied directly from node *i*,
α_{i}^{u} :	Set of buses supplying directly bus *i*,
$D_{ij,k}^{g}$:	Topological distribution factors.

Based on the proportional sharing principle, the reactive power can be also traced and priced. Using the topological distribution factors based on the upstream-looking algorithm, transmission usage charge is allocated to individual generators. Alternatively, using the topological distribution factors based on the downstream-looking algorithm, transmission usage charge is allocated to individual loads.

2. Kirschen's Tracing Method

Kitshchen's tracing method is based on a set of definitions for domains, commons, and links [Kir 1997, Kir 1999]. A domain is a set of buses that obtain power from a particular generator. A common is a set of contiguous buses supplied by the same set of generators. Links are branches that interconnect commons. After the definitions, the state of the system is represented by a directed graph that consists of commons and links, with directed flows between commons and the corresponding data for generations/loads in commons and the flows on links. As for the Bialek's tracing method, this method assumes that the proportion of inflow traced to a particular generator is equal to the proportion of outflow traced to the same particular generator for a given common.

Starting from a root common, the method finds recursively the contribution of each common's generator (load) to line flows and consumed loads. Here a proportionality assumption is used to contribute the outflow of a common to the inflow of a common. Finally, usage cost of a transmission system can be allocated to generators or loads on the basis of their contribution to each branch flow.

3.4 Comparison of Embedded Pricing Methods

Table 3.1 summarizes aforementioned embedded pricing paradigms include non-flow-based and flow-based pricing methods.

Table 3.1: Summary of embedded pricing methods

Embedded Pricing Methods	Application	Load Flow Analysis	Cost Based on	Restriction
Postage stamp	• Real power • Generation and load	N/A	• Magnitude of transacted power • An average embedded cost	Depends on the assumption that the entire transmission system is used
Contract path	• Real power • Generation and load	N/A	• Magnitude of transacted power • An average embedded cost	Depends on the assumption that the wheeling is restricted to flow along a specified and artificial path
Boundary flow	• Real power • Generation and load	DC	• Magnitude of transacted power • An average embedded cost	Depends on the assumption that the boundary lines connect between wheeling companies
MW-mile & Enhanced MW-mile	• Real power • Generation and load	DC	• Magnitude of transacted power • Path of the transacted power • Distance travel by the transacted power • Individual network asset cost	Depends on operational conditions and system configuration
Distribution factors GSDFs (A factor)	• Real power • Generation and load	DC	• Incremental line flow • Individual network asset cost	Depends on system configuration, selection of reference bus, and power flow directions
Distribution factors GGDFs (D factor)	• Real power • Generation	DC	• Total line real flow • Individual network asset cost	Depends on operational conditions and system configuration
Distribution factors GLDFs (C factor)	• Real power • Load	DC	• Total line real flow • Individual network asset cost	Depends on operational conditions and system configuration
AC flow sensitivity indices & Transaction assessment	• Real and reactive power • Generation and load	AC	• Total flow • Individual network asset cost	Depends on operational conditions, system configuration, and detailed network cost information

Embedded Pricing Methods	**Application**	**Load Flow Analysis**	**Cost Based on**	**Restriction**
Tracing	• Real and reactive power • Generation and load	AC	• Total flow • Individual network asset cost	Depends on operational conditions

3.5 Incremental/Marginal Pricing Methods

Incremental/marginal pricing methods assign part or all of the incremental cost of accommodating a transmission transaction directly to that transaction. There are two factors associated with these methods. One is for the concern of time either short-run or long-run, which has been explained in Chapter 2. The other is the factor of pricing based on either incremental or marginal cost. The major difference between incremental cost and marginal cost is how the additional transaction is estimated. Incremental cost is based on comparing the transmission costs with or without the entire additional transaction. The marginal cost approach calculates the cost of a unit of additional transaction, and multiplies the cost of a unit by the size of the additional transaction [Sha 2002, Shi 1996]. Incremental/marginal pricing methods are mainly used to determine the price of a transmission transaction. They are also used in the composite pricing paradigm to determine the incremental component of transmission prices.

3.5.1 Short-Run Incremental Cost (SRIC)

The short-run incremental cost pricing methodology evaluates and assigns the operating cost associated with an additional transmission transaction to the existing transactions. The transmission transaction operating costs can be estimated using an optimal power flow model that accounts for all operating constraints, including transmission system constraints and generation scheduling constraints [Shi 1996]. As introduced in chapter 2, the operating cost, opportunity cost and existing cost are the most significant factors in the SRIC pricing methodology. It should be noted that the SRIC of a transmission transaction could be negative.

There are several concerns related to the SRIC pricing method. Firstly, in order to provide timely economic signals to transmission customers, there are serious technical challenges involved in accurately evaluating and forecasting the operating cost. Secondly, it is difficult to allocate the SRIC among several transactions that are collectively responsible for changes in operating cost. Thirdly, SRIC can not make efficient economic decisions for long-term transmission transaction. Therefore, the SRIC pricing method is a limited concept, difficult to execute in electricity markets.

3.5.2 Long-Run Incremental Cost (LRIC)

The long-run incremental cost pricing methodology entails all the costs including the reinforcement cost to accommodate a new transmission transaction. The standard LRIC pricing method uses a traditional system planning approach to determine reinforcements that are required, and corresponding investment schedules with and without each transaction [Hap 1994]. The basic steps include:

1. Preliminary calculation, with which all the cost and investment data are prepared.
2. Computations of annual revenue requirement (ARR) and the present worth revenue requirement (PWRR) of each reinforcement project.
3. Change in PWRR without all reinforcement projects, and with all reinforcement projects.

4. Allocate the change in PWRR to each transaction. There are four separate methods: $/MW allocation, $/MWMile allocation, interface flow allocation by regions, and one by one allocation [Hap 1994].

The reinforcement cost component can be evaluated based on the changes caused by long term transmission plans due to the transmission transaction. Although the concept of LRIC is straightforward, the forecasting reinforcement cost scenarios become more and more inaccurate as time goes by. It should be noted that LRIC methodologies are difficult to numerically evaluate.

3.5.3 Short-Run Marginal Cost (SRMC)

The short-run marginal cost for any point in time associated with the operation of the electric power sector as a whole is the marginal cost of supplying an additional unit of demand holding the capital stock constant [Tab 1994]. The marginal operating cost is the cost of accommodating a marginal increase in the transacted power. The Marginal operating cost per MW can be estimated as the difference in the optimal cost of power at all points of delivery and receipt of that transaction, which can be calculated using OPF sensitivity methods [Mer 1989, Gri 1990]. The marginal operating cost is then multiplied by the magnitude of the transacted power to get the SRMC. SRMC prices are normally higher than the actual operating cost, in order to provide the profit to fund future transmission expansion. But if the magnitude of the transacted power is large compared to the magnitude of the native load in the transmission system, short run marginal costs will fall far short, discouraging the transmission reinforcement.

The earliest SRMC evolved from the theory of an hourly spot price [Sch 1985, Car 1986]. The spot wheeling rate are used for different types of wheeling: utility-to-utility, customer-to-customer, customer-to-utility, and utility-to- customer. Wheeling

Rate Evaluation Simulator (WRATES) is the one of earliest computer program for SRMC calculation, based on marginal operating cost and revenue reconciliation adjustments for capital recovery [Car 1989]. There are many SRMCs that have been developed, which include JUANAC/Transcost (ITT, Madrid) [Rub 2000], ESCORT (CEGB modified by NGC, UK) and PSS/OPF (PTI, Schenectady, NY). SRMC is usually used to correct and balance the transmission fixed cost [Jin 2003].

3.5.4 Long-Run Marginal Cost (LRMC)

The long-run marginal cost is defined as the marginal cost of supplying an additional unit of energy, when the installed capacity of the system is allowed to increase optimally in response to the marginal increase in demand. As such, it incorporates both capital and operating costs for the system as a whole.

In this pricing methodology, the marginal operating and reinforcement costs of the power system are used to determine the final prices for a transmission transaction. The marginal operating cost is as the same as the short run marginal cost, and the reinforcement cost is determined with a similar approach using the long run incremental cost. The long run marginal cost prices will influence transmission expansions, hence avoid the disadvantage of short run marginal cost prices. The main concern is the applicability and the allocation of long run marginal cost prices.

Compared with SRMC, LRMC provides a simpler calculation process since the values are calculated based on long term plans. While they are stable within an annual time frame, they tend to be more volatile for calculation of network values on a year to year basis, because they are affected by the timing of individual investment decisions. There are two existing examples. Developed by the National Grid Company (NGC), UK, the first is called the Investment Cost-Related Pricing (ICRP) model. The other is called the DC load flow Investment Cost-Related Pricing (DCLF

ICRP) model [Bak 2001]. ICRP was introduced without load flow calculation in 1993/94, and was replaced by DCLF ICRP in April, 2004. The details of DCLF ICRP are described in the following section.

3.6 Investment Cost Related Pricing (ICRP) in the UK

In theory, it is desirable that generation is placed as close as possible to the demand centre. In practice, demand centres are physically located in urban areas, where generation capacity additions are difficult. Therefore, there are various transmission pricing methodologies employed in different countries to operate the transmission networks more effectively.

Background information of the electrical power market in the UK has been introduced in the first chapter. Here follows the detailed application of NGC's Investment Cost Related Pricing (ICRP), which can be treated as a long run marginal cost methodology [Ngc 2006b].

The NGC Transmission Network Use of System (TNUoS) tariff comprises two separate elements. One is a locational varying element derived from the DCLF Investment Cost Related Pricing (ICRP) transport model, to reflect the costs including capital investment cost, maintenance and operation cost. The other is a non-locationally varying element related to the provision of residual revenue recovery.

The process for calculating the TNUoS is divided into three steps:

1. The DCLF ICRP transport model.

2. Calculation of zonal marginal km.
3. Deriving the final £/KW tariff.

3.6.1 The DCLF ICRP Transport Model

On 1st April 2004, National Grid implemented a new use of system charging methodology, among other things, a DC load flow (DCLF) ICRP Transport Model that replaces the original ICPR Transport Model. The DCLF ICRP transport model calculates the marginal cost of investment in the transmission system, which is required as a consequence of an increase in demand or generation at each node based on a peak condition study. The DCLF ICRP transport model enable the differentiation of the basic nodal costs to be determined, and also allows sensitivity analysis concerning alternative developments of generation and demand to be undertaken [Ngc 2006b].

For the purposes of the DCLF Transport algorithm, it has been assumed that the value of circuit impedance is equal to the value of circuit reactance (ignore the resisters). Consider the following 3 nodes network:

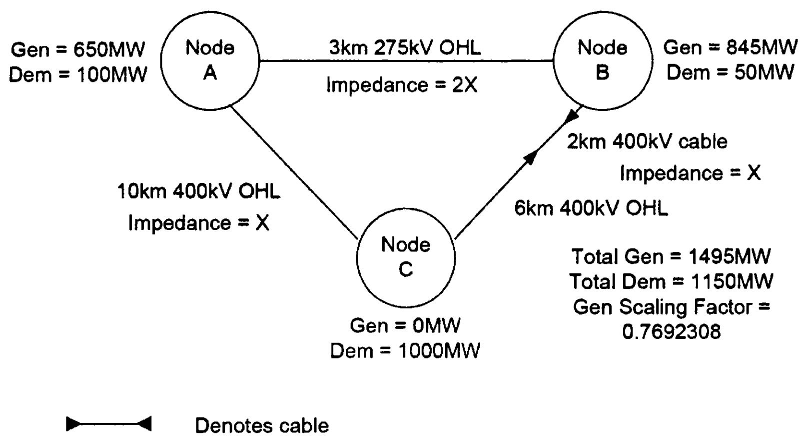


Figure 3.4: DCLF ICRP transport model (1) [Ngc 2006b]

The first step is to match total demand and total generation by scaling uniformly the nodal generation down such that total system generation equals total system demand.

Node A Generation = 1150 / 1495 · 650 MW = 500 MW

Node B Generation = 1150 / 1495 · 845 MW = 650 MW

This gives the following balanced system:

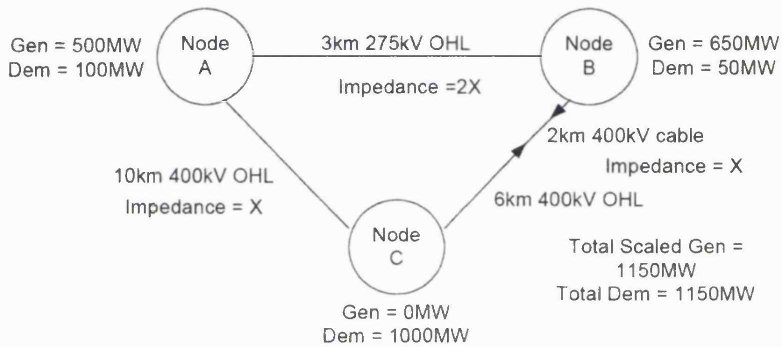


Figure 3.5: DCLF ICRP transport model (2) [Ngc 2006b]

Assuming Node A is the reference node, each circuit has impedance X. The 400kV cable circuit expansion factor is 10 and the 275kV overhead line circuit expansion factor is 2, the DCLF transport algorithm calculates the base case power flows as follows:

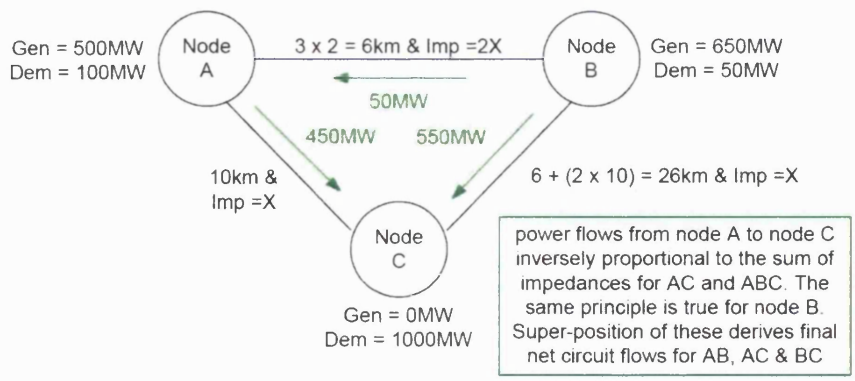


Figure 3.6: DCLF ICRP transport model (3) [Ngc 2006b]

Nodes A and B export, whilst Node C imports. Hence the DCLF algorithm derives flows to deliver export power from Nodes A and B to meet import needs at Node C.

Step 1: Net export from Node A is 400MW; route AC has impedance X and route AB-BC has impedance 3X; hence 300MW would flow down AC and 100MW along AB-BC

Step 2: Net export from Node B is 600MW; route BC has impedance X and route BA-AC has impedance 3X; hence 450MW would flow down BC and 150MW along BA-AC

Step 3: Using super-position to add the flows derived in Steps 1 and 2 derive the following;

Flow AC = 300 MW + 150 MW = 450 MW

Flow AB = 100 MW – 150 MW = -50 MW

Flow BC = 100 MW + 450 MW = 550 MW

Total cost = (450 * 10) + (50 * 6) + (550 * 26) = 19,100 MWkm

(Base case)

We then 'inject' 1MW of generation at each node with a corresponding 1MW offtake (demand) at the reference node and recalculate the total MWkm cost. The difference in cost from the base case is the marginal km or shadow cost. This is demonstrated as follows:

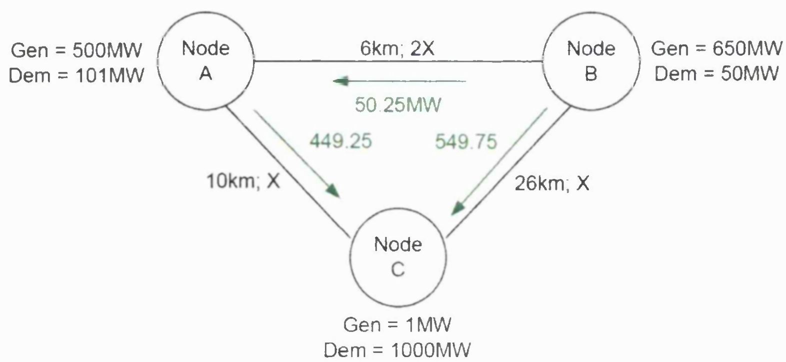


Figure 3.7: DCLF ICRP transport model (4) [Ngc 2006b]

To calculate the marginal km at node C:

Total Cost = (449.25 * 10) + (50.25 * 6) + (549.75 * 26) = 19,087.5 MWkm

Thus the overall cost has reduced by 12.5 (i.e. the marginal km = -12.5).

3.6.2 Calculation of Zonal Marginal KM

The nodal marginal km is amalgamated into zones by weighting them by their relevant generation or demand capacity. The criteria are used to determine the zonal boundaries [Ngc 2006b]:

1. Zones should contain relevant nodes whose marginal costs are all within +/- £1/KW across.
2. The nodes within zones should be geographically and electrically proximate.
3. Relevant nodes are considered to be the only ones with generation connected to them, which contribute to the calculation of the zonal generation tariff.

The zonal marginal km for generation is calculated as:

$$WNMkm_j = \frac{NMkm_j \cdot Gen_j}{\sum_{j \in Gi} Gen_j} \tag{3.32}$$

$$ZMkm_{Gi} = \sum_{j \in Gi} WNMkm_j \tag{3.33}$$

Where,

j:	Node,
Gi:	Generation zone,
Gen:	Nodal generation from the transport model,
NMkm:	Nodal marginal km form transport model,
WNMkm:	Weighted nodal marginal km,

ZMkm: Zonal marginal km.

Similarly, the zonal marginal km for demand is calculated as:

$$WNMkm_j = \frac{-1 \cdot NMkm_j \cdot Dem_j}{\sum_{j \in Di} Dem_j} \tag{3.34}$$

$$ZMkm_{Di} = \sum_{j \in Di} WNMkm_j \tag{3.35}$$

Where,

Di: Demand zone,

Dem: Nodal demand from the transport model.

3.6.3 Deriving Final £/KW Tariff

The zonal marginal costs are converted into costs by multiplying the marginal costs by the expansion constant and locational security factor.

The expansion constant (£/MWkm) represents the annual value of the transmission infrastructure capital investment required to transport 1 MW over 1 km. Because the circuit expansion factors take nodal marginal cost into consideration, the expansion constant is determined from the manufactures' budgetary prices of 400 KV overhead line. For 2006/2007 it is £10.07/MWkm [Ngc 2006b].

The security factor is derived using a Secured DCLF (SECULF) program which calculates the marginal cost for each node, taking into account the requirement to secure against a set of contingencies. The secure and intact marginal costs are compared on a nodal basis and a "least squares fit" employed to derive the GB security factor [Ngc 2006b].

1. Correct Transport Tariff

$$(ZMkm_{Gi} + C) \cdot EC \cdot LSF = CTT_{Gi} \tag{3.36}$$

$$(ZMkm_{Di} - C) \cdot EC \cdot LSF = CTT_{Di} \tag{3.37}$$

Where,

C: Generation/Demand split correction constant (km), which is to meet $CTT_{Gi} / CTT_{Di} = 27 / 73$. This has been determined by the Authority for generation and demand respectively [Ngc 2006b],

EC: Expansion factor (£/MWkm),

LSF: Locational security factor,

$ZMkm_{Gi}$: Zonal marginal km for each generation zone (km),

CTT_{Gi}: "Generation/Demand split" corrected transport tariff for each generation zone (£/MW),

$ZMkm_{Di}$: Zonal marginal km for each demand zone (km),

CTT_{Di}: "Generation/Demand split" corrected transport tariff for each demand zone (£/MW).

$$\sum_{Gi=1}^{21} (CTT_{Gi} \cdot G_{Gi}) = CTRR_G \tag{3.38}$$

$$\sum_{Di=1}^{14} (CTT_{Di} \cdot D_{Di}) = CTRR_D \tag{3.39}$$

$CTRR$: Generation / Demand split corrected transport revenue.

2. The Residual Tariff

$$RT_D = \frac{(p \cdot PTRR) - CTRR_D}{\sum_{Di=1}^{14} D_{Di}} \tag{3.40}$$

$$RT_G = \frac{((1-p) \cdot PTRR) - CTRR_G}{\sum_{Gi=1}^{21} G_{Gi}} \tag{3.41}$$

Where,

RT: Residual tariff (£/MW),

p: Proportion of revenue to be recovered from demand (27%),

PTRR: Total transport revenue (£),

CTRR: Generation / Demand split corrected transport revenue (£).

3. Final £/KW Tariff

$$FT_{Di} = \frac{CTT_{Di} + RT_D}{1000} \tag{3.42}$$

$$FT_{Gi} = \frac{CTT_{Gi} + RT_G}{1000} \tag{3.43}$$

Where,

FT: Final TNUoS tariff (£/KW).

To sum up, in order to calculate the generation tariffs, it is necessary to evaluate a generation weighted zonal marginal km cost, modify by a re-referencing quantity to ensure that the revenue recovery split between generation and demand is correct, multiply by the security factor, then add a constant (termed the residual cost) to get the overall tariff. Example of the zonal generation and demand tariff are shown in Appendix A-1 and Appendix A-2.

Chapter 4

Pricing Methodologies of Distribution Networks

Besides the efficient pricing of transmission networks, pricing methodology of distribution networks has been another cornerstone of the ongoing decentralized market. With the explanation of distribution network pricing regulations, this chapter reviews pricing methodologies of distribution networks. Finally, the use of system charging methodology of the UK's distribution company demonstrates the bottom-up pricing scheme under price cap regulation.

4.1 Chapter Introduction

As described in Chapter three, transmission pricing has reached a certain maturity in the last decade, during which many methods had been proposed. Contrarily, given the limited number of distribution-connected generation in the past, the tariffs of distribution networks are similar to postage stamp rate, which has been introduced as the earliest and simplest of transmission pricing methodologies. The distribution prices are mainly set for suppliers and large customers according to their voltage levels and types, regardless of locations, network configuration, power flow, and so on. The pricing structure also treats distribution-connected generation very differently from demand customers and transmission-connected generation.

Following the development of generators' technology and the aspiration of a low carbon future, more new small-scale embedded generators are planning to connect to the distribution network. Thus, the non-discriminatory access to distribution network is the vehicle for promoting the necessary competition in generation and suppliers. Distribution tariffs that are too high or too low, or inappropriately structured, will hamper efforts to facilitate true competition. The existing distribution methodologies run out of their ability to produce an economic price signal for generators.

Because the whole transmission network is firmly interconnected and operated co-ordinately, the characteristic of the transmission network is commonly described as a "grid". How to determine the extended use of the system for network users is a key issue for all the transmission pricing methodologies. However, the distribution network is described as "radial". Since all new connection assets, once installed and energised, become part of the distribution system, there is an inevitably close association between connection charge and "use of system" charging. Moreover, the way in which each user accesses the distribution system can be different at the same connection point. The direct application of the transmission pricing methods to the distribution system seems difficult, especially when the voltages are lower than 11KV. The reason being there is no metering and data below 11KV. The nature of the network makes it very complex to keep a track on all the assets of urban and rural areas, and identify the impact of each distribution user on the expansion of this system [Lim 2002]. So a long term distribution pricing methodology is still a challenge for government, industries, and researchers [Jam 2005, Str 2005, Tur 2005]. The existing pricing methodologies of distribution networks will be reviewed following an explanation of distribution network pricing regulations.

4.2 Regulation of Distribution Network Pricing

Since distribution business is still a monopoly, it cannot be presided from economic regulation. Although it is necessary to define an allocation rule for the allowed revenue, which is periodically established by the regulator, the regulation concerning price control plays a more important role than the price allocation in a traditional distribution business. There are two main approaches to preventing monopolistic infrastructure companies from charging excessively high prices: rate of return regulation and incentive regulation [Lim 2002]. Incentive regulation includes price cap regulation and yardstick competition regulation.

4.2.1 Rate-of-return and Incentive

Rate of return regulation means that the regulator will set the excepted rate of return on the distribution network owners' (DNOs) capital. The central idea is that monopoly companies should be required to charge the price that would prevail in a competitive market, which is equal to efficient costs of production plus a market determined rate of return on capital. Rate of return regulation has been criticised because it encourages more capital investment than it needs. Contrarily, incentive regulations have been applied in order to incentive the company to be more efficient. Whatsoever, the major task of distribution regulation is to ensure that tariff settings allow the company to recover its costs plus a reasonable return on its capital, taking into account the risks faced by the company, while promoting incentives to achieve greater efficiency [Rud 2000].

In practice, the distinction between rate-of-return regulation and incentive regulation may be lost, as regulators may end up making implicit decisions on the acceptable real rates of return on capital employed, in order to arrive at price limit determinations.

4.2.2 Price Cap and Yardstick Competition

Price cap and yardstick competition are two main types of incentive regulation.

Price cap regulation occurs when the regulator sets caps on service prices that the utility is allowed to charge. The prices are adjusted periodically to account for inflation, technological progress and exogenous changes. Revenue cap regulation is the same as price cap regulation except the company's revenue is restricted by the inflation-productivity index [Jami 2005]. Compared with rate of return regulation, price cap regulation has two advantages. Firstly, it provides incentives for distribution companies to improve efficiency, to minimize short-term costs. Since prices are fixed in short-term, any short-term cost reductions achieved by the utility are translated directly into increased profits. Secondly, it is relatively easy to implement a price cap on the regulator's operational view [Sas 2006]. However, in the long run, the low price caps will defer the investment to keep the potential upside profits, and the high price caps will encourage distribution companies to invest in new capacity, in order to increase their production therefore leading to market surplus. Thus, price cap regulation can produce an inefficient signal for research and development. This problem can be ameliorated by a regulatory lag between the implementation of a technological advancement and the resulting price cap change, giving the utility time to fully benefit from the technological advancement [Lim 2002].

In the UK, price cap has been used to regulate the newly privatized utilities industry since the mid 1980s. It is very well known as the official Retail Price Index, minus X (RPI-X), a percentage reflecting the excess of a target growth rate of efficiency for the regulated industry over the average growth rate of efficiency for the whole country [Tur 1997]. Under the RPI-X form of regulation, the regulator can control the change in average prices charged by a utility so that they do not exceed the increase in inflation.

Yardstick regulation approach aims to make private monopoly companies compete with a reference efficient fictitious model company. So it is also called "benchmark regulation". The scheme compares the real distribution company with a model company, established in specific geographical areas, reflecting the differences introduced by economics of scope arising from population density and the size of networks [Rec 2002]. The rewards or penalties are based on selected dimensions of service performance. The regulator may adjust the measures of performance to account for differences among suppliers in operational conditions [Lim 2002]. Yardstick regulation brings an element of competition into regulation, and also aids the regulator by making the distribution cost and operation information more reliable and easier to obtain. Although more complex to apply, yardstick regulation seems to be more suitable to the distribution activity, and the concepts are currently under development by several South American countries, such as Chile, Brazil [Rud 2000, Lim 2002].

4.3 Distribution Pricing Methods

The approaches to calculate the distribution price are very basic and limited. The methods to calculate the base price include top-down and bottom-up, which come from two strategies of information processing and knowledge ordering, and a proposed framework from the University of Manchester Institute of Science and Technology (UMIST) [Str 2005].

4.3.1 Top-down

Under the top-down approach, moving from general to specific, the distribution base price is derived by subtracting generation, transmission and commercialization costs from the traditional whole electricity price. The price can then be applied into various components of the distribution network. Because the top-down approach begins with the big picture and wide-angle views, the top-down model has advantage of staying focused on the goal. It facilitates the energy regulator to control the energy price. One of the disadvantages is that it usually keeps distortions from the old regime. It may be used as an interim approach, so as not to impose a sudden impact on the balance of the distribution companies, which is currently the case in Brazil.

4.3.2 Bottom-up

By contrast, under a bottom-up approach, the distribution base price is calculated by analyzing the cost of distribution service components, regardless of the full-service cost. It is necessary for each distribution company to identify each circuit and substation belonging to their system. Because the price is derived from the individual parts and detailed components, the bottom-up method makes more sense than the top-down method in distribution system. Another advantage is that it is more attractive and more consistent with transmission pricing methods. Although it is a major challenge for energy regulator to decide how deep it should go in terms of scanning all cost components. Form the bottom-up approach, it is possible to create a distribution model as a yardstick model, to serve as the basis for the yardstick regulation.

4.3.3 UMIST's Model

The UMIST model is a symmetrical area-differentiated approach to the estimate of the long-run unit distribution cost of demand and of distributed generation [Tur 2005]. Figure 4.1 shows the steps in the derivation of time of use location network use of system charges.

The advantages of UMIST's model include: it recognises the interaction of generation and demand, it analyzes the power flow on each separate part of the network in the identified periods, including maximum load and secure generation output (summer off-peak), minimum load and maximum generation (winter peak), it produces nodal price rather than aggregative results. There remains some weakness with this model. Although the size of the incremental demand is the appropriate dimension for ascertaining the need for additional distribution network capacity in demand dominated asset analysis, it is not always true for accommodating distributed generation in generator dominated asset analysis. Distributed generation requires extra assets for stability, voltage quality, and fault level limit. The prices for generation are probably much greater than for demand. Also this model is not based on marginal or any other economic concept, so it is difficult to give an efficient cost-benefit signal.

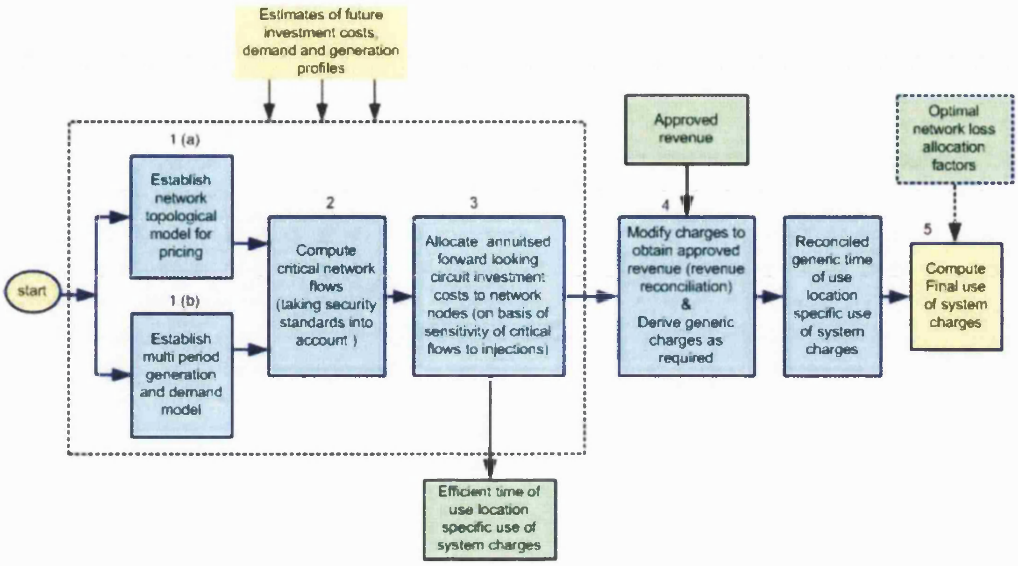


Figure 4.1: UMIST's model [Str 2005]

4.4 Distribution Reinforcement Model (DRM) in the UK

Although the total amount of revenue is constrained by the energy regulator, the costs of providing a distribution service need to be calculated, in order that they can be recovered from the system users through an appropriate tariff structure.

In the UK, the initial distribution pricing model for assessing the incremental capacity cost was introduced by the Electricity Council in 1984. Under the price cap regulation, which is of RPI-X form, the distribution pricing methodology based on

Distribution Reinforcement Model (DRM) is currently the major approach, which is one of the bottom-up pricing methodologies.

In DRM, Network asset costs are based on the increment in the assets and equipments at each voltage level, to support a 500MW increment in simultaneous maximum demand. The quantities in the model are consistent with engineering planning policy, including assets in proportion to the existing network, and are based on equipment available today [Wpd 2006a]. Because the DRM model is a theoretical 500MW extension to the distribution system, it is also called 500MW model. The final tariff is calculated by the yardstick, which means the benchmark of cost in different voltage or transformation levels. The final tariff is designed for demand customers only.

DRM calculation includes two steps. The first step is to determine yardstick tariffs for each class of customer. The second step is scaling these yardstick tariffs to ensure that the revenues covered through use of system charges match the allowed revenue.

4.4.1 Calculation of Yardstick Tariffs

The yardstick tariff consists of the required transformer capacity at each system level, to meet demand and security to normal industry planning guidance, allowing for the use of standard size equipment and typical utilisation factors. It also consists of appropriate overhead lines and underground cables at each voltage level, to reflect the actual mix of the existing network and typical utilisation factors.

In this, separate costs are identified for each normal level of network and transformation, and leads to a model of the network costs and yardsticks. For example, there are seven levels in Western Power Distribution (WPD) company's charging methodology. They include 132KV network, 132/33KV transformation, 33KV network, 33/11KV transformation, 11KV network, 11KV/LV network and LV network.

The steps to calculate the yardstick tariffs are as follows:

1. Estimate the scaling factor between the system Simultaneous Maximum Demand (SMD) and 500MW. SMD may be measured in the higher voltage level substations from transmission system.

$$ScalingFactor = \frac{SMD}{500} \tag{4.1}$$

2. Investigate the quantities or lengths of distribution system components at each voltage or transformation level.

$$"500MW"Unit_{asset} = \frac{OriginalUnit_{asset}}{ScalingFactor} \tag{4.2}$$

asset: different types of distribution asset, including overhead circuits, underground cables, transformers, switching gears etc.

3. Using the unit cost of each asset and the quantities from Step 2, calculate the total asset reinforcement cost to meet 500 MW demand.

$$"500MW"Cost_{asset} = UnitCost_{asset} \cdot "500MW"Unit_{asset} \tag{4.3}$$

4. Calculate yardsticks for each voltage or transformation level with diversity factor. The diversity factor is defined as the ratio of the sum of the individual maximum demand of the various parts of a distribution system to meet the system SMD, which is always greater than unity.

$$YardStick_v = \frac{\sum_{asset=1}^{N} "500MW"Cost_{asset}}{500{,}000 \cdot DiversityFactor_v} \tag{4.4}$$

v: different voltage or transformation levels,

N: the number of total asset at level v, *YardStick*$_v$: cost benchmark at level v. (£/KW).

5. Taking losses into account, calculate the cumulated cost for each voltage or transformation level.

$$CumulatedCost_D = \sum_{v \in D} \left(YardStick_v \cdot (1 + Loss_v\%) \right) \quad (4.5)$$

CumulatedCost$_D$: final cost at level D (£/KW),

Loss$_v$*%*: Percentage of loss at peak hours at level v.

v: upstream voltage or transformation levels for calculating the cumulated cost at level D,

Steps 1-5 are the general yardstick calculation process for different classes of customers, and are also the fundamental principle of the DRM pricing scheme. In Table 4.1 is a demonstration of base steps 1-5 of a DRM 500MW incremental example at 132KV and 33KV.

Table 4.1: Distribution reinforcement model 500MW incremental example at 132KV and 33KV [Tur 2005]

System components	**Unit cost (£000)**	**"500MW" Quantities or lengths (KM)**	**"500MW" Cost (£000)**	**Cost per SMD (£/KW)**	**Diversity factor**	**Cost per AMD (£/KW)**	**Losses at peak hours**	**Cost per AMD (£/KW)**	**Cumulated cost per AMD (£/KW)**
Transmission exit charge				15					
132 KV circuits (per KM)									
Switch bay	520	6	3,120						
400 mm^2 cable	1,102	7.31	7,400						
175 mm^2 cable	960	2.44	2,340						
175 mm^2 overhead dual circuit	333	44.36	14,773						
175 mm^2 overhead single circuit	168	23.89	4,013						
			31,646	63.29					
				78.29	1.06	59.71	1.0%	60.31	74.60
132/32 KV substation									
2 · 90 MVA substation	713	5	3,565						
2 · 90 MVA substation	564	1	564						
			4,129	8.26	1.06	7.79	2.0%	7.95	82.55
33 KV circuits (per KM)									
Urban 300 mm^2 cable	196	140	27,440						
Rural 175 mm^2 overhead dual circuit	60	60.8	3,648						
Rural 175 mm^2 overhead single circuit	38	15.2	578						
			31,666	63.33	1.06	59.75	2.0%	60.94	143.49

Simultaneous Maximum Demand (SMD) = 500,000

Cost per SMD = "500MW" cost / 500,000

"500MW" Cost = Unit cost · "500MW" Quantities or lengths.

Cost per Average Maximum Demand (AMD) = Cost per SMD / Diversity factor

6. Using the cumulated costs, calculate the per KWH cost of the different customers in the same voltage level, who have various energy consumptions and different coincidence factors according to the upstream use of network.

$$PerKWH_C = CumulatedCost_v \cdot (Units / KW)_C \cdot CF_C \tag{4.6}$$

C: customers class *C*,

PerKWH$_C$: use of network cumulated cost base on energy for customers class *C*,

(Units/KW)$_C$: energy consumption for customers class *C*,

CF$_C$: coincidence factor for customer class *C*.

7. The yardstick tariffs of different classes of customers are added to the operation & maintenance cost and other miscellaneous costs to the cost per KWH cost from Step 6.

$$Tariff_C = PerKWH_C + O \& M_C + Other_C \tag{4.7}$$

Step 6-7 are diverse between different distribution zones based on their own characteristics in the UK.

4.4.2 Deriving Final Tariff Based on Yardstick Tariff

Yardsticks are used with forecasts of consumption in the tariff charging periods for each class of customer to produce a forecast of total yardstick revenue. The individual yardsticks are then scaled by the same factor to meet the target revenue, taking into account regulatory entitlement.

$$FinalTariff_{customer} = Tariff_{customer} * ScalingFactor_{customer} \tag{4.8}$$

Based on the above equations, the following are two examples of yardstick calculation from Western Power Distribution Company (WPD). The first one is from

South West of England distribution service zone, and the second one is from South Wales distribution service zone [Wpd 2006a].

Example of Yardstick	**Profile 1**		**WPD South West**		
kWh/kW	3662				
			£/kW/yr	p/kWh	Coincidence
132kV System			14.27	0.355	0.911
132kV System Losses	@	8.0%		0.028	
132/33kV Substation			2.48	0.057	0.911
132/33kV Losses	@	7.3%		0.004	
33kV System			4.99	0.115	0.911
33kV System Losses	@	6.6%		0.008	
33/11kV Substation			6.26	0.145	0.911
33/11kV S/S Losses	@	5.9%		0.009	
11kV System			18.26	0.422	0.911
11kV System Losses	@	5.0%		0.021	
11kV/LV Substation			4.60	0.121	0.950
11kV/LV S/S Losses	@	3.4%		0.004	
LV System			6.97	0.168	0.950
LV System Losses	@	1.1%		0.002	
Total 500MW Model Costs				1.459	
Power Factor Deviation Cost				-0.073	
Service Cost			0.77	0.009	1.000
Subtotal				1.394	
Miscellaneous Costs				0.000	
Total Network Costs				1.394	
Plus Working Capital	@	0.773%		0.011	
Consumer Related Costs				0.156	
Operational Rates				0.163	
NGC Exit Charges				0.035	
Total Yardstick				1.760	
Scaling		107.30%			
Scaled Yardstick				1.889	

Note: An adjustment for customer contributions has been applied at the LV system level and has a value of 50%.

Figure 4.2: DRM from WPD South West [Wpd 2006a]

Example of Yardstick	**Profile 1**		**WPD South Wales**		
kWh/kW	3662				
			£/kW/yr	p/kWh	Coincidence
132kV System			16.42	0.408	0.911
132kV System Losses	@	6.8%		0.028	
132&66/33kV Substation			2.27	0.056	0.911
132&66/33kV Losses	@	6.2%		0.003	
66&33kV System			3.57	0.089	0.911
66&33kV System Losses	@	5.6%		0.005	
132,66&33/11kV Substation			6.21	0.154	0.911
132,66&33/11kV S/S Losses	@	5.0%		0.008	
11kV System			16.25	0.404	0.911
11kV System Losses	@	4.2%		0.017	
11kV/LV Substation			3.89	0.101	0.950
11kV/LV S/S Losses	@	2.9%		0.003	
LV System			5.72	0.148	0.950
LV System Losses	@	0.9%		0.001	
Total 500MW Model Costs				1.426	
Power Factor Deviation Cost				-0.071	
Service Cost			1.10	0.030	1.000
Subtotal				1.385	
Total Network Costs				1.385	
Plus Working Capital	@	0.773%		0.011	
Indirect Overheads				0.209	
Operational Rates				0.202	
NGC Exit Charges				0.042	
Total Yardstick				2.296	
Scaling		118.97%			
Scaled Yardstick				2.198	

Note: An adjustment for customer contributions has been applied at the LV system level and has a value of 50%.

Figure 4.3: DRM from WPD South Wales [Wpd 2006a]

From the above description and examples, DRM can not produce generation pricing. Since 1st April 2005, in the UK, OFGEM - the energy regulator, have proposed a mechanism for distribution-connected generation [Wpd 2006a]. This mechanism allows DNOs to recover a percentage of the reinforcement assets, either from the individual generator or the population of generators. The distributed generators are charged based on DNO's projected reinforcement costs associated with connecting to a certain voltage level. So it is a regulated and fixed price.

Overall, under the government's price cap regulation, DRM is designed to meet DNO's allowed revenue by estimating the capacity cost of accommodating a postulated increment in the SMD met at each voltage level of 500MW. It could not meet the objectives of an efficient network pricing methodology in open access distribution networks.

Chapter 5

LRMC-DC and LRMC-AC

Firstly, the long-run marginal cost (LRMC) pricing methodology based on DC power flow calculation is formulated and explained in this chapter. Using two novel approaches that have been developed to set the price for reactive power, a new LRMC-AC pricing methodology is introduced and formulated. One IEEE standard test system, and one practical distribution test system are employed to demonstrate and compare LRMC-DC and LRMC-AC. With the advantage of reactive power price, the results show that LRMC-AC outperforms LRMC-DC on system capital cost recovery.

5.1 Chapter Introduction

A review of transmission pricing methodologies in Chapter 3 reveals that they have been progressively developed over the years to become more sophisticated. Pricing methodologies based on marginal cost have the natural advantage of giving efficient economic signals, and have achieved a dominant position in many countries' transmission pricing schemes. In the previous chapter, the review of existing pricing methodologies of distribution networks shows their weakness in following the trend of distribution network open access. DRM used in the UK fails to produce a price for generation. Therefore, in this chapter, NGC's DCLF Investment Cost Related Pricing (ICRP) model is taken as the starting point. Initially a long-run marginal cost based on DC power flow (LRMC-DC) is formulated using the same concept. Besides the IEEE-30 bus test system, LRMC-DC is tested on a practical 110 bus distribution test system with 24 customer-connected nodes. This was chosen from the electrical network in South Wales, and serviced by the Western Power Distribution (WPD) company. It is a demonstration of an existing transmission pricing methodology on distribution network above 11KV. This is also an original research about the impact of LRMC pricing methodology on distribution networks.

LRMC-DC pricing methodology ignores the price of reactive power. It is therefore unfair to different customers and DNOs, as reactive power plays an important role in electricity network operation and security. Although a few transmission pricing methods can allocate reactive power costs, such as transaction assessment methods and tracing methods, there is no direct research about reactive power price based on LRMC. This chapter proposes two new reactive power pricing methodologies. They can extend LRMC-DC into LRMC based on AC power flow calculation (LRMC-AC), and form one of the main contributions of this research. The two reactive power pricing methodologies are explained and formulated. The LRMC-AC pricing method is also tested on the IEEE-30 bus test system and the distribution test system as mentioned above. In comparison with LRMC-DC, the results are presented and analyzed at the end.

5.2 LRMC-DC

5.2.1 Principle

The DCLF ICRP model as introduced in Chapter 3, is a practical example of a long-run marginal cost pricing scheme. Based on the same principle, LRMC-DC is introduced as the basic marginal cost pricing methodology.

The definition of LRMC has been explained in Chapter 2. LRMC-DC means that the marginal cost calculation is based on a DC power flow calculation. Therefore, there is no cost assigned to reactive power, being convenient to allocate all the cost to real power. The principle of LRMC-DC is estimating the cost change based on the usage of the electricity network increase or decrease, for a unit real power injection into, or withdrawal, from the system. The process of LRMC pricing methodology can be summarized as:

1. Evaluate the network asset's unit cost,
2. Calculate the power flow changes of each network asset due to the marginal injection or withdrawal at a node,
3. Based on the unit cost of system and power flow changes, obtain the marginal cost for the node.

The power flow calculation is one of the essential elements in the whole process. Power flow is a steady state of a power system given the sets of conditions, which has various solutions [Glo 2001, Gra 1994, Pan 2006, Woo 1996]. Newton-Raphson power flow calculation has been selected as a typical approach, for use in this research.

5.2.2 Asset Unit Cost Evaluation

1. Estimation of the network asset costs

Transmission and distribution assets consist of two main parts: circuit related assets, and substation related assets. The circuit related assets comprise different types and lengths of overhead line and underground cable. There are various components in substations, including transformers, circuit breakers, isolators, busbars, structures, protection, control panels and so on. Because transformers are primary components of a substation, which account for half of the substation cost, it assumes that the total cost of the substation can be shared by the numbers of transformers.

$$Asset_l = \begin{cases} UC_O \cdot L_{Ol} + UC_U \cdot L_{Ul} & \text{for circuit} \\ T_l & \text{for transformer} \end{cases} \tag{5.1}$$

Where,

$Asset_l$: the cost of asset l (£),

UC_O, UC_U: the unit cost of overhead line and underground cable, which represent the network infrastructure capital investment cost over unit length (£/KM),

L_{Ol}, L_{Ul}: the length of overhead line and underground cable belonging to the circuit l (KM),

T_l: the unit cost of transformer l (£).

2. Annuity Factor

The asset costs are expected to be covered during their lifespan, in which the annuity factor plays an important role in spreading the asset costs across their designed life.

The definition of annuity factor is the present value at a discount rate of an annuity of £1 paid at the end of each of *ny* periods.

$$AnnuityFactor = \frac{1}{d} - \frac{1}{d \cdot (1+d)^{ny}} \tag{5.2}$$

To explain the annuity factor in the above equation, the concept of discount factor is firstly introduced. Discount factor is how much £1 at a future date is worth today, also called the present worth factor and the present worth of £1.

$$DiscountFactor = \frac{1}{(1+d)^{ny}} \tag{5.3}$$

Where,

d: the discount rate (expected rate of return),

ny: the number of years.

Rate of return is the remuneration to investment stated as a proportion or percentage. The financial rate of return is the internal rate of return based on market prices. The economic rate of return is the internal rate of return of a cash flow, expressed in economic prices. Here the expected rate of return is the financial rate of return proposed by network companies and approved by the energy regulatory.

Form the above equation,

$$PV = DiscountFactor \cdot FV \tag{5.4}$$

Where,

PV: present value,

FV: future value.

If a cash flow has already been defined as the difference between money received and money paid, each year's future cash flow can be discounted to its present value by dividing it by the discount factor for that year.

$$PV = \frac{M}{1+d} + \frac{M}{(1+d)^2} + \frac{M}{(1+d)^3} + \ldots + \frac{M}{(1+d)^{ny}} \tag{5.5}$$

Where,

M: expected annual cash flow of discount rate d.

In a power system, PV is the current investment and is a fixed cost. The expected annual cash flow is the annual future value to be covered.

$$
\begin{aligned}
PV &= \left(\frac{1}{1+d} + \frac{1}{(1+d)^2} + \frac{1}{(1+d)^3} + \ldots + \frac{1}{(1+d)^{ny}}\right) \cdot M \\
&= \left(\frac{1}{d} - \frac{1}{d(1+d)^{ny}}\right) \cdot M
\end{aligned}
\tag{5.6}
$$

Using,

$$AnnuityFactor = \frac{1}{d} - \frac{1}{d \cdot (1+d)^{ny}}$$

Therefore,

$$PV = AnnuityFactor \cdot M$$

The annual cashed flow is decided by the network companies' approved rate of return. The annuity factor is used to find the annual worth of the present value.

3. Defining the asset universal unit cost

Evaluate the universal unit cost (£/(year·MW)) for real power of both circuits and transformers,

$$UC_l = \frac{Asset_l}{AnnuityFactor \cdot Capacity_l} \tag{5.7}$$

$Capacity_l$: the capacity of asset l (MW).

5.2.3 LRMC-DC Formulation

The process and formulation of LRMC-DC are explained in the following six steps.

1. Setting up the system model

Prepare network data to set up the system model. The data required includes system asset costs and network data for power flow calculation, such as, the data for busbars, circuits, transformers, generators and demands. The generators outputs and demands change from time to time. From the view of the network planning and design, the network agreed capacities of generators are taken. The simultaneous maximum demand (SMD) of the system is taken as the demands data.

2. Base use of network cost

In the initial network, the power flow $BaseP_l$ in each circuit and transformer can be defined from the power flow calculation. Then the base use of network cost (£/year) can be calculated as below:

$$BaseCost_l = BaseP_l \cdot UC_l \tag{5.8}$$

$$TotalBaseCost = \sum_{l=1}^{L} BaseCost_l \tag{5.9}$$

Where,

L: total number of the network assets.

3. Injection for marginal cost calculation

In the LRMC-DC pricing method, a unit real power n (MW) is injected into a certain node N to demonstrate the base load profile with a marginal increase. To keep the balance between generators and demand, the unit injection needs to be withdrawn from a defined load centre, which is assumed as the slack bus in the transmission network, or the grid supply point in the distribution network.

4. New use of network cost

The power flow $NewP_l$ in each circuit and transformer is calculated according to the new load profile with the unit of real power injection. So,

$$NewCost_l = NewP_l \cdot UC_l \tag{5.10}$$

$$TotalNewCost = \sum_{l=1}^{L} NewCost_l \tag{5.11}$$

5. Calculation of the marginal cost for node *N*

Define the marginal cost (£/(year·MW)) according to real power *n* (MW) injection at the node *N*.

$$MC_N = \frac{TotalNewCost - TotalBaseCost}{n} \tag{5.12}$$

6. Calculation of the marginal cost for each node

Inject a unit of real power *n* (MW) into each node, and repeat steps 3-5 to get the marginal cost for demand at all nodes.

In Step 3, using unit of real power *n* (MW) withdrawal instead of injection, the marginal cost for the generator at the node *N* can be calculated. Because generators can be treated as negative loads, and the unit of real power *n* (MW) is selected as a marginally small value, generator cost is approximately opposite to the value of demand cost at the same node.

5.3 Reactive Power Pricing Methodologies

In the above LRMC-DC pricing method, the final cost is only allocated on real power. Practically, reactive power plays an important role in providing the network security and maintaining voltages, especially for the lower voltage levels of the distribution network. In addition to encouraging the use of sustainable energy, embedded generators require numbers of reactive power compensators or SVCs placed in various locations of the network to support the voltage quality. It is unreasonable to ignore the reactive power price in network pricing methodology. Without reactive power prices, network owners cannot distinguish between good or poor power factors of network users. So it is necessary to devise a network pricing methodology implementing reactive power charges. From the formulation of the LRMC-DC, the unit cost is calculated from the assets cost, annuity factor and asset capacity. In this section, there are two approaches to split the unit cost into real and reactive parts. The *perpendicular approach* and *arc approach* derive their names from the triangular relationship between real, reactive and apparent power. The *perpendicular approach* is introduced in [Li 2005, Li 2006], and is a co-operative work done with the author. The *arc approach* is another novel solution, which is mainly employed in the studies of this thesis. Both reactive power pricing methods are detailed explained in following subsections.

5.3.1 Perpendicular Approach

Based on the fundamental principles of electrical circuit theory, the apparent power S_l of the circuit l in vector formulation is defined as:

$$\vec{S_l} = P_l \cdot i + Q_l \cdot j \tag{5.13}$$

Where,

P_l: the real power of circuit l,

Q_l: the reactive power of circuit l.

From Figure 5.1, the magnitude of apparent power S_l of the circuit l can be described as:

$$S_l = P_l \cdot \cos\theta_l + Q_l \cdot \sin\theta_l \tag{5.14}$$

Where,

$\cos\theta_l$: Power factor of circuit *l*.

$\sin\theta_l = \sqrt{1-\cos^2\theta_l}$

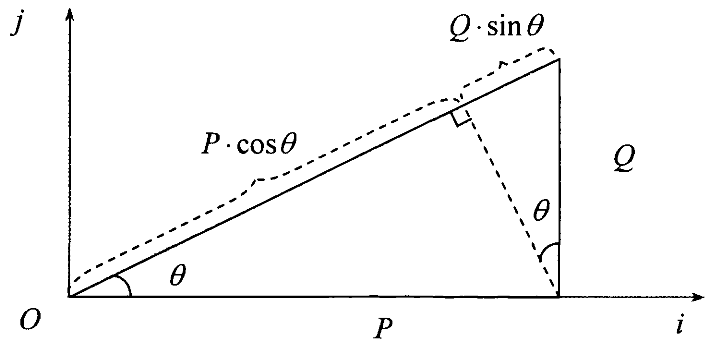


Figure 5.1: Perpendicular approach

In the LRMC-DC model, the unit cost of each circuit was defined as

$$UC_l = \frac{Asset_l}{AnnuityFactor \cdot Capacity_l}$$

So the unit cost is based on the full capacity of the line, rather than real power. Multiplying both sides of Equation 5.14 by UC_l gives:

$$S_l \cdot UC_l = P_l \cdot \cos\theta_l \cdot UC_l + Q_l \cdot \sin\theta_l \cdot UC_l \tag{5.15}$$

In the above equation, the cost of used line capacity S_l is described into two parts, the costs which are related to P_l and Q_l. So the unit costs for real power and reactive power can be defined as:

$$UCP_l = \cos\theta_l \cdot UC_l \tag{5.16}$$

$$UCQ_l = \sin\theta_l \cdot UC_l \tag{5.17}$$

Where,

UCP_l: unit cost of line *l* for real power,

UCQ_l: unit cost of line *l* for reactive power.

Both UCP_l and UCQ_l are defined based on the perpendicular relationship between apparent power and real/reactive power, so this method is called the "*perpendicular approach*". In this approach, the power factor is used to separate the unit cost. Since the power factor will vary according to real and/or reactive power change, the unit costs for real power and reactive power are dependent on each other. As shown in Figure 5.2, because the reactive power increases from Q to Q', the new unit cost will be:

$$UCP_l' = \cos\theta_l' \cdot UC_l \tag{5.18}$$

$$UCQ_l' = \sin\theta_l' \cdot UC_l \tag{5.19}$$

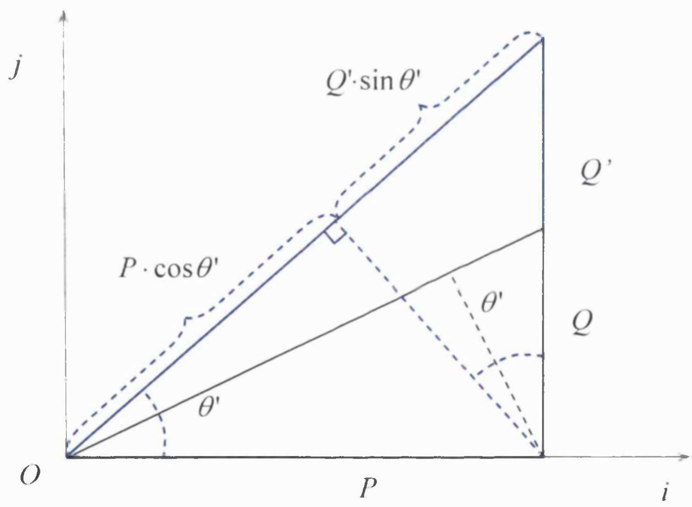


Figure 5.2: Perpendicular approach with various Q

To avoid the disturbance from reactive power and keep the independent unit cost of real power, the *arc approach* is introduced later.

5.3.2 LRMC-AC with Perpendicular Approach

With the *perpendicular approach* to allocate the reactive power cost, the LRMC-AC formulation is modified from LRMC-DC as below:

1. Setting up the system model

Prepare the system data as in the LRMC-DC pricing method.

2. Base use of network cost

In the base network, the power flow $BaseP_l$ and $BaseQ_l$ of each circuit and transformer can be defined from the power flow calculation. Using the unit costs of real and reactive power defined in Equation 5.16 and 5.17, the base use of network real and reactive cost (£/year) can be calculated as below:

$$TotalBaseCostP = \sum_{l=1}^{L} BaseCostP_l = \sum_{l=1}^{L} \left(BaseP_l \cdot UCP_l\right) \tag{5.20}$$

$$TotalBaseCostQ = \sum_{l=1}^{L} BaseCostQ_l = \sum_{l=1}^{L} \left(BaseQ_l \cdot UCQ_l\right) \tag{5.21}$$

3. Injection for marginal cost calculation

In the LRMC-AC pricing method, a unit of power n (MW) + n (MVAR) is injected into a certain node N to demonstrate the base load profile with a marginal increase.

4. New use of network cost

The power flow $NewP_l$ and $NewQ_l$ of each circuit and transformer is calculated according to the new load profile with the unit power injection. So,

$$TotalNewCostP = \sum_{l=1}^{L} NewCostP_l = \sum_{l=1}^{L} \left(NewP_l \cdot UCP_l\right) \tag{5.22}$$

$$TotalNewCostQ = \sum_{l=1}^{L} NewCostQ_l = \sum_{l=1}^{L} (NewQ_l \cdot UCQ_l) \tag{5.23}$$

5. Calculation of the marginal cost for node *N*

Define the marginal cost (£/(year·MW) and £/(year·MVAR)) according to unit of power *n* (MW) + *n* (MVAR) at the node *N*.

$$MCP_N = \frac{TotalNewCostP - TotalBaseCostP}{n} \tag{5.24}$$

$$MCQ_N = \frac{TotalNewCostQ - TotalBaseCostQ}{n} \tag{5.25}$$

6. Calculation of the marginal cost for each node

Inject a unit of power *n* (MW) + *n* (MVAR) into each node, and repeat steps 3-5 to get the marginal cost for demand of all nodes.

In Step 3, using unit power *n* (MW) + *n* (MVAR) withdrawal instead of injection, the marginal cost for generator at the node *N* can be calculated. As suggested in Section 5.2.3, generators can be treated as negative loads and the unit power is selected as a marginally small value, generator price is approximately opposite to the value of demand price at the same node.

5.3.3 Arc Approach

Compared with the *perpendicular approach*, the "*arc approach*" makes an arc instead being perpendicular in the triangle relationship between apparent, real and reactive power, as shown below.

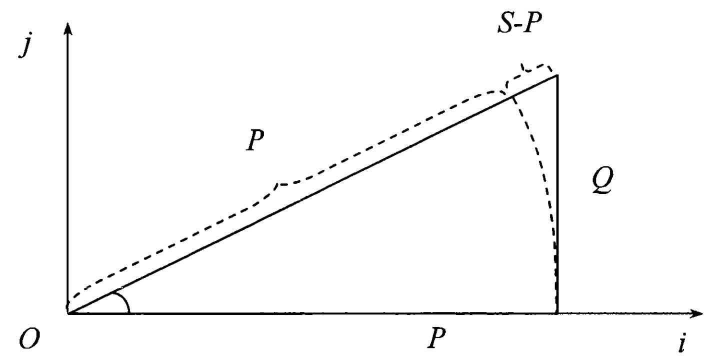


Figure 5.3: Arc approach

From the above diagram, the magnitude of apparent power S for the line l can be described as real power plus the contribution from reactive power.

$$S_l = P_l + (S_l - P_l) = P_l + Q_{l,contrib} \tag{5.26}$$

Because,

$$S_l = \frac{P_l}{\cos\theta_l} = \frac{P_l}{pf_l}$$

pf_l: Load power factor of node l.

The contribution from reactive power can be formatted as:

$$Q_{l,contrib} = S_l - P_l = \frac{P_l}{pf_l} - P_l = \frac{1 - pf_l}{pf_l} \cdot P_l \tag{5.27}$$

In the LRMC-DC model, the unit cost of each circuit is defined as:

$$UC_l = \frac{Asset_l}{AnnuityFactor \cdot Capacity_l}$$

So multiplying both sides of Equation 5.26 by UC_l gives:

$$S_l \cdot UC_l = P_l \cdot UC_l + Q_{l,contrib} \cdot UC_l \tag{5.28}$$

Compared with LRMC-DC, the LRMC-AC with *arc approach* calculates the contribution from reactive power based on the same unit cost. So the results of the

LRMC-AC with *arc approach* can maintain the same unit cost with Q change, as shown in Figure 5.4.

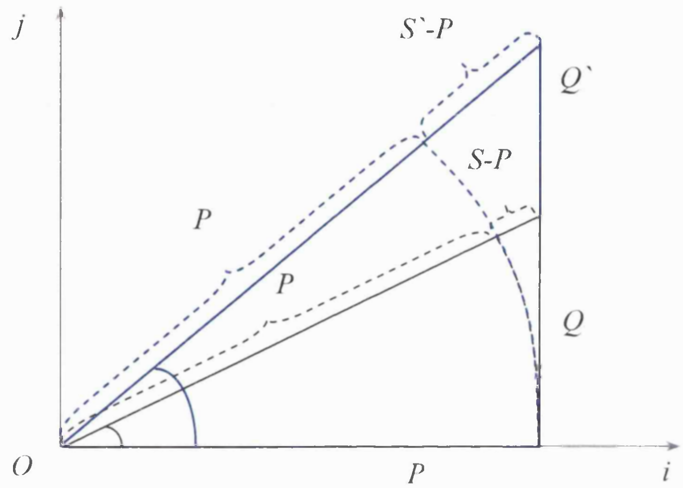
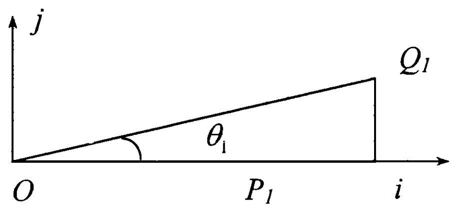
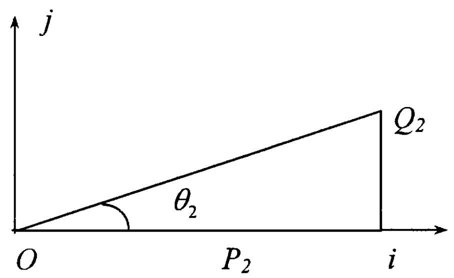


Figure 5.4: Arc approach with various Q

To clarify the difference between the *perpendicular approach* and the *arc approach*, an example is set to verify the cost change, due to the change of reactive power. It assumes there is a transmission line A. The unit cost of line A is £10/KW. Two loading conditions are proposed as shown in Figure 5.5. Under the loading condition 1, the power flow on the line A is 10MW with 0.98 lagging power factor. Under the loading condition 2, the magnitude of real power keeps the same as the loading condition 1, but the power factor changes from 0.98 to 0.95. It also means that the reactive power flow increases from 2.03MVAr to 3.29MVAr. Based on the two loading conditions, the cost of real and reactive power by the two different reactive power pricing methods can be calculated, respectively.





Loading condition 1:

10MW with power factor 0.98

$P_1 = 10MW \quad Q_1 = 2.03MVAR$

$\cos\theta_1 = 0.98 \quad \sin\theta_1 = 0.20$

$S_1 = 10.20MVA$

Loading condition 2:

10MW with power factor 0.95

$P_2 = 10MW \quad Q_2 = 3.29MVAR$

$\cos\theta_2 = 0.95 \quad \sin\theta_2 = 0.31$

$S_2 = 10.53MVA$

Figure 5.5: Example with various Q

Using the *perpendicular approach*, the unit cost of real power reduces when reactive power flow increases, as calculated in Table 5.1. With the increasing of reactive power flow, the total recovered cost raises from £102, 000 to £105,000 according to more total power consumption. But the recovered cost from real power reduces from £98, 000 to £95,000, which is due to the unit cost of real power decrease. The reason of the unit cost of real power change is the unit cost calculation depends on the power factor, as shown in Equation 5.18, Equation 5.19, and Figure 5.2.

Table 5.1: Perpendicular approach results

	load		Unit Cost		Cost Recovered		
	P(MW)	Q(MVAr)	P(£/KW)	Q(£KVAr)	P(£000)	Q(£000)	Total(£000)
Loading 1	10	2.03	9.8	2.0	98	4	102
Loading 2	10	3.29	9.5	3.1	95	10	105

Using the *arc approach*, the unit cost of real power and reactive power keep the same under the both loading conditions, as shown in Table 5.2. Compared with the *perpendicular approach*, the change of the final total recovered cost is same, which indicates both reactive power pricing methods can match the same financial goal. Furthermore, the *arc approach* can ensure that the total recovered cost from real power keeps the same, regardless of the variation of reactive power. The variation of reactive power flow only causes the change of the recovered cost from reactive component.

Table 5.2: Arc approach results

	load			Unit Cost	Cost Recovered		
	P(MW)	Q(MVAr)	$\lvert S\rvert - \lvert P\rvert$	(£/unit)	P(£000)	Q(£000)	Total(£000)
Loading 1	10	2.03	0.20	10	100.0	2	102
Loading 2	10	3.29	0.53	10	100.0	5	105

Therefore, unlike the *perpendicular approach*, the unit cost of real and reactive power by the *arc approach* is independent of the power factor. As an objective of desirable pricing method, it is more appropriate to keep the independence of the real and reactive power cost. From the above demonstration, the *arc approach* is also simpler to interpret to network users than the *perpendicular approach*.

Overall, both the *perpendicular approach* and the *arc approach* are novel methods to evaluate the cost of reactive component, which help recover more network cost. From the comparison, the advantage of the *arc approach* is using a unique unit cost to reflecting the reactive cost, keeping the cost of real power stable with the different power factor, more reasonable to explain the reactive power prices to network users due to their reactive power consumption. So, the *arc approach*, as a new reactive power pricing concept, is employed in the further studies of this thesis. More analysis and implementation of the *perpendicular approach* can refer to the attached authors' papers [Li 2005a, Li 2006].

5.3.4 LRMC-AC with Arc Approach

With the *arc approach* to allocate the reactive power cost, the LRMC-AC formulation is modified from LRMC-DC as below:

1. Setting up the system model

Prepare the system data as in the LRMC-DC pricing method.

2. Base use of network cost

In the base network, the power flow $BaseP_l$ and $BaseS_l$ of each circuit and transformer is be defined from the power flow calculation. Then the base use of network real and reactive cost (£/year) can be calculated as below:

$$BaseQ_{l,contrib} = BaseS_l - BaseP_l \tag{5.29}$$

$$TotalBaseCostP = \sum_{l=1}^{L} BaseCostP_l = \sum_{l=1}^{L} \left(BaseP_l \cdot UC_l\right) \tag{5.30}$$

$$TotalBaseCostQ = \sum_{l=1}^{L} BaseCostQ_l = \sum_{l=1}^{L} \left(BaseQ_{l,contrib} \cdot UC_l\right) \tag{5.31}$$

3. Injection for marginal cost calculation

In the LRMC-AC pricing method, a unit of power n (MW) + n (MVAR) is injected into a certain node N to demonstrate the base load profile with a marginal increase.

4. New use of network cost

The power flow $NewP_l$ and $NewS_l$ of each circuit and transformer is calculated according to the new load profile with the unit of power injection. So,

$$NewQ_{l,contrib} = NewS_l - NewP_l \tag{5.32}$$

$$TotalNewCostP = \sum_{l=1}^{L} NewCostP_l = \sum_{l=1}^{L} \left(NewP_l \cdot UC_l\right) \tag{5.33}$$

$$TotalNewCostQ = \sum_{l=1}^{L} NewCostQ_l = \sum_{l=1}^{L} \left(NewQ_{l,contrib} \cdot UC_l\right) \tag{5.34}$$

5. Calculate the marginal cost for node *N*

Define the marginal cost (£/(year·MW) and £/(year·MVAR)) according to unit power n (MW) + n (MVAR) at the node N.

$$MCP_N = \frac{TotalNewCostP - TotalBaseCostP}{n} \tag{5.35}$$

$$MCQ_N = \frac{TotalNewCostQ - TotalBaseCostQ}{n} \tag{5.36}$$

6. Calculate the marginal cost for each node

Inject a unit of power n (MW) + n (MVAR) into each node, and repeat steps 3-5 to get the marginal costs for demand at all nodes.

In Step 3, using unit power n (MW) + n (MVAR) withdrawal instead of injection, the marginal cost for a generator at the node N can be calculated. As noted earlier, generators can be treated as negative loads and the unit power is selected as a marginally small value, generator cost is approximately opposite to the value of demand cost at the same node.

5.4 Results and Analysis

Based on the explanation and formulation for LRMC-DC and LRMC-AC detailed in Subsection 5.2.3 and 5.3.4, respectively, both methodologies are tested on the IEEE-30 bus test system, and a distribution test system which was chosen from the South Wale distribution network, in the UK. The results are presented and analyzed below.

5.4.1 IEEE-30 Bus Test system

The IEEE-30 bus test system represents a portion of the American Electric Power System in Virginia as of December, 1961 [Pow 2006]. The original test system does not have line thermal limits and costs. For the purpose of the network pricing, the costs of lines were estimated based on the geographical constraints. The detailed system data is shown in Appendix B-1. Node 1 was chosen as the slack bus.

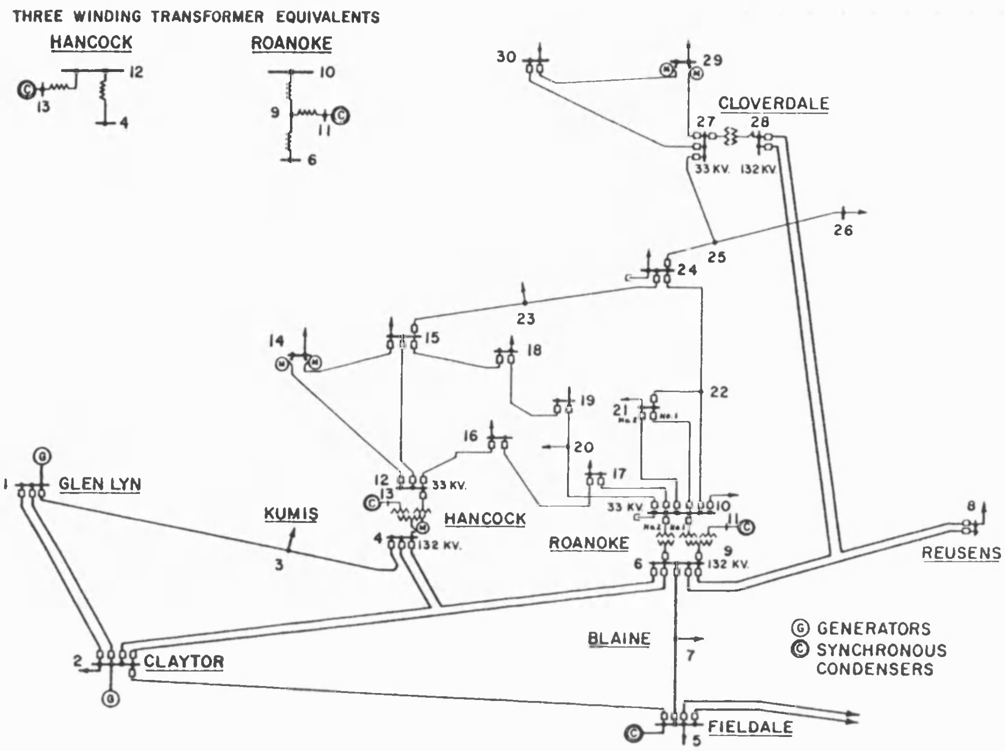


Figure 5.6: IEEE-30 bus test system [Pow 2006]

Table 5.3 and Table 5.4 show the results from LRMC-DC and LRMC-AC, respectively. The negative sign before the price means the demand will be paid for using the network, which is the case when the usage of network from these customers will reduce network congestion. It also means the network owner benefits from these customers, based on the current network loading condition. The price based on marginal cost is for demand, so the price for generation will be the negative equivalent of the values shown in the tables.

Table 5.3: LRMC-DC results on IEEE-30 bus test system

	Marginal Cost (£/unit/Yr) for Demand		Cost Recovered (£000/Yr)		
NO.	P(£/KW/Yr)		P(£000/Yr)		Total(£000/Yr)
2	4.62		-84.55		-84.55
3	7.42		17.82		17.82
4	10.71		81.41		81.41
5	23.71		2,233.67		2,233.67
6	15.80		0.00		0.00
7	16.28		371.09		371.09
8	25.07		752.16		752.16
9	16.92		0.00		0.00
10	17.81		103.29		103.29
11	17.65		0.00		0.00
12	11.66		130.64		130.64
13	12.78		0.00		0.00
14	11.90		73.77		73.77
15	15.11		123.92		123.92
16	15.39		53.88		53.88
17	18.68		168.09		168.09
18	19.04		60.91		60.91
19	21.59		205.14		205.14
20	20.85		45.86		45.86
21	20.25		354.32		354.32
22	20.17		0.00		0.00
23	19.97		63.89		63.89
24	24.25		210.96		210.96
25	21.97		0.00		0.00
26	26.73		93.54		93.54
27	20.47		0.00		0.00
28	20.30		0.00		0.00
29	24.66		59.19		59.19
30	29.37		311.30		311.30
	Total		5,430.31		5,430.31

Without the reactive power price, the total cost recovered is from real power pricing only. Zero cost recovered at certain nodes means that no customer connected to those nodes.

Table 5.4: LRMC-AC results on IEEE-30 bus test system

	Marginal Cost (£/unit/Yr) for Demand		Cost Recovered (£000/Yr)		
NO.	**P(£/KW/Yr)**	**Q(£/KVAr/Yr)**	**P(£000/Yr)**	**Q(£000/Yr)**	**Total(£000/Yr)**
2	4.76	-0.68	-87.14	25.40	-61.74
3	7.52	2.58	18.06	3.10	21.15
4	10.78	3.33	81.89	5.32	87.21
5	24.90	-6.24	2,345.20	112.25	2,457.45
6	15.86	3.37	0.00	0.00	0.00
7	16.62	4.84	378.84	52.72	431.57
8	25.17	-2.44	755.07	17.82	772.89
9	17.25	4.58	0.00	0.00	0.00
10	18.28	5.68	106.02	11.36	117.39
11	17.96	2.91	0.00	-47.11	-47.11
12	11.65	4.49	130.45	33.68	164.12
13	12.77	2.21	0.00	-23.37	-23.37
14	11.34	4.79	70.31	7.67	77.98
15	15.47	5.46	126.85	13.64	140.49
16	15.57	5.39	54.50	9.70	64.20
17	19.13	6.15	172.18	35.68	207.86
18	19.53	6.49	62.51	5.84	68.35
19	22.17	7.30	210.60	24.81	235.41
20	21.41	6.96	47.10	4.87	51.97
21	20.86	6.92	365.09	77.49	442.58
22	20.77	6.93	0.00	0.00	0.00
23	20.39	7.67	65.24	12.27	77.51
24	24.72	9.48	215.07	63.53	278.60
25	21.90	10.09	0.00	0.00	0.00
26	26.98	12.26	94.43	28.20	122.63
27	20.01	10.16	0.00	0.00	0.00
28	20.25	10.41	0.00	0.00	0.00
29	24.37	11.65	58.48	10.49	68.97
30	29.18	12.69	309.35	24.11	333.46
Total			5,580.07	509.47	6,089.54

The first advantage of LRMC-AC is the allocation of reactive power cost. As a result, it can recover more revenue than LRMC-DC, which can be seen from Figure 5.7.

The total annual asset capital cost required to be covered is £13,384.76k. LRMC-AC can cover 45.5% of total capital cost, which is 5% more than LRMC-DC.

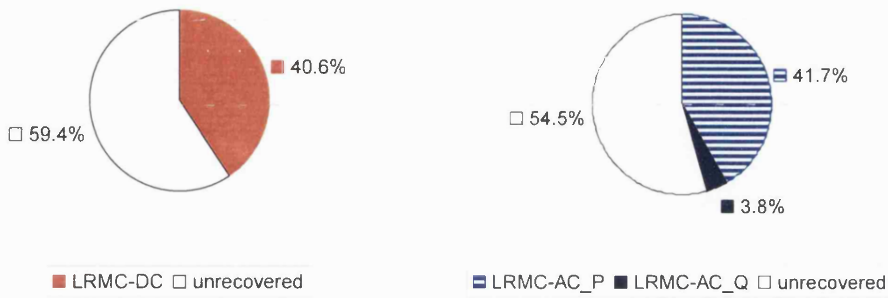


Figure 5.7: LRMC-DC and LRMC-AC cost recovery on IEEE-30 bus test system

In Figure 5.8, the nodal marginal cost of LRMC-DC and LRMC-AC methods are presented together. The real power prices of LRMC-DC and LRMC-AC are very similar, which means both methods are locational based methodologies. From the electrical network connection, nodes 1-8, and 28 are in the 132KV network. Considered with the geographical condition, nodes 5 and 8 are farther away from the slack bus than other 132KV nodes, so they have higher prices than their neighbouring nodes. The nodes in the 33KV and 11KV network are connected with shorter distances. Their prices tend to change gradually and smoothly with their neighbouring nodes.

Besides the locational signal, the reactive power price of LRMC-AC will be decided by the cost difference between the line's apparent power and real power. For example, nodes 24-30 with loads having poor power factor in their area, are penalized (about 10 £/KVAr/Yr) by reactive power consumption. Loads at nodes 5 and 8 are rewarded by using redundant reactive power from the existing synchronous condensers.

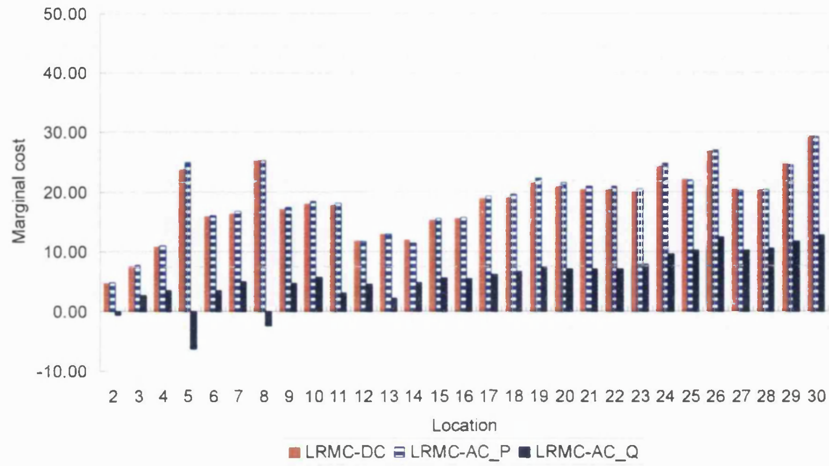


Figure 5.8: LRMC-DC and LRMC-AC price comparison on IEEE-30 bus test system

5.4.2 Distribution Test System

To demonstrate the results of the above two different LRMC pricing mechanisms, a practical network is chosen to be the test network. The criterion of the test network should truly reflect the configuration of distribution networks. It should contain the various characteristics of the typical demands, which include the urban, rural and average customers. A test network based on a South Wales distribution network supplied by the Western Power Distribution (WPD) company, UK, is modified to match the criterion of a typical network. It concentrates on the EHV networks (132KV, 33KV, 33/11KV transformation). The geographic map is shown below in Figure 5.9 [Wpd 2006b]. It includes 110 buses, 81 lines, 54 transformers, and 24 customer-connected nodes. The total annual capital cost required to be covered is £11,080.32k. The detailed system data is shown in Appendix B-2.

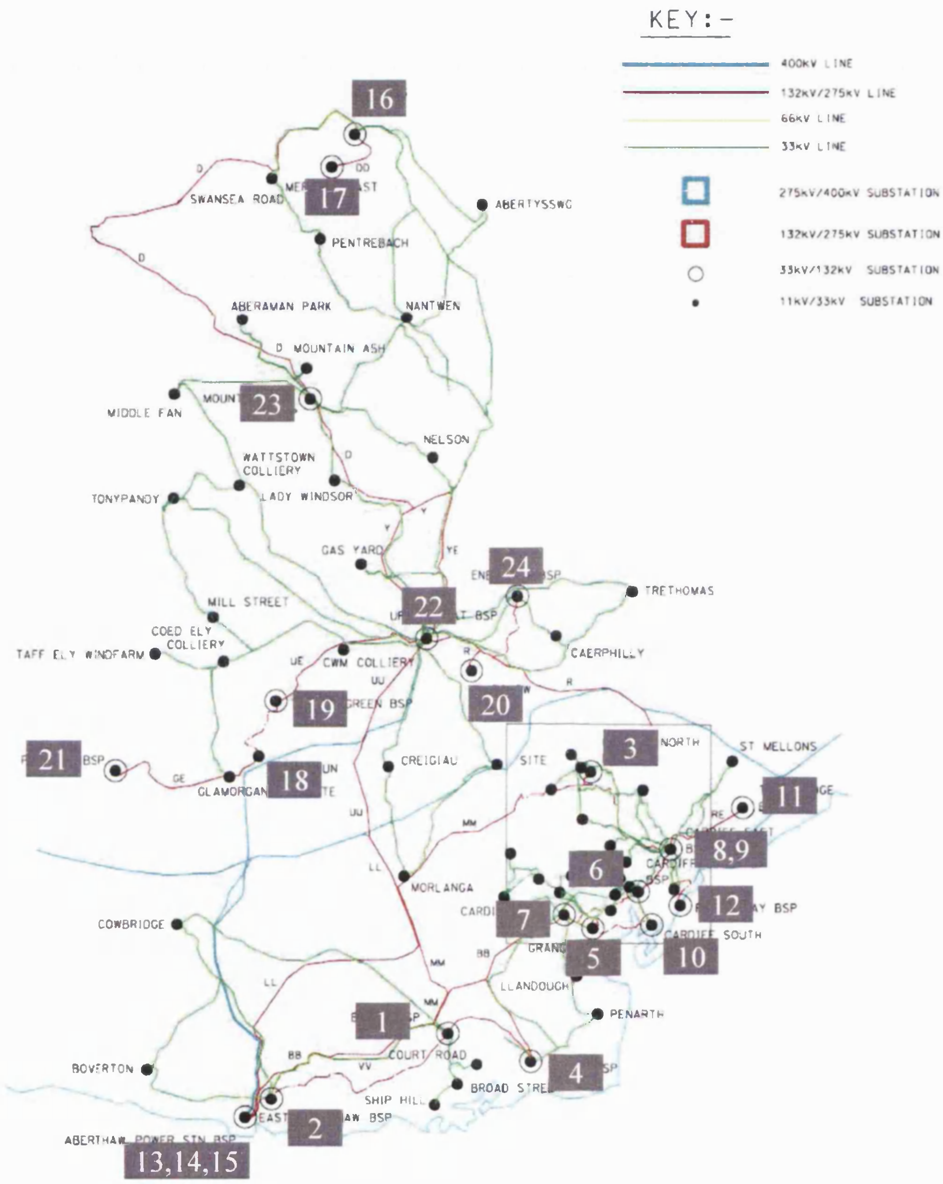


Figure 5.9: Geographic map of distribution test system [Wpd 2006b]

Table 5.5 and Table 5.6 show the results of applying LRMC-DC and LRMC-AC on the distribution test system, respectively. Considering the reality, only customer connected nodal prices are shown in the tables. As noted earlier, the negative sign before the price means the demand will be paid for using the network. It also means the network owner benefits from these customers, based on the current network loading condition. For instance, nodes 13, 14 and 15 have large generators connected, so the nodal prices are negative, which encourage the location demand to increase.

Table 5.5: LRMC-DC on distribution system

	Marginal Cost (£/unit/Yr) for Demand		Cost Recovered (£000/Yr)		
NO.	P(£/KW/Yr)	Q(£/KVAr/Yr)	P(£000/Yr)	Q(£000/Yr)	Total(£000/Yr)
1	1.52		52.71		52.71
2	2.11		51.96		51.96
3	4.63		185.71		185.71
4	2.90		59.99		59.99
5	5.52		115.96		115.96
6	6.66		216.75		216.75
7	8.59		697.58		697.58
8	7.28		747.35		747.35
9	9.26		275.80		275.80
10	6.40		195.32		195.32
11	11.45		84.72		84.72
12	7.77		60.57		60.57
13	-2.65		85.72		85.72
14	-2.65		452.30		452.30
15	-2.65		151.28		151.28
16	20.45		661.40		661.40
17	22.61		590.09		590.09
18	14.19		217.14		217.14
19	9.94		238.63		238.63
20	8.34		133.44		133.44
21	18.71		312.47		312.47
22	7.57		174.00		174.00
23	13.25		154.64		154.64
24	11.04		126.94		126.94
Total			6,042.47		6,042.47

Table 5.6: LRMC-AC on distribution test system

	Marginal Cost (£/unit/Yr) for Demand		Cost Recovered (£000/Yr)		
NO.	P(£/KW/Yr)	Q(£/KVAr/Yr)	P(£000/Yr)	Q(£000/Yr)	Total(£000/Yr)
1	1.55	-0.94	53.72	-3.25	50.46
2	1.81	3.31	44.56	57.57	102.13
3	4.67	-0.34	187.11	-2.23	184.88
4	2.89	0.37	59.76	3.07	62.83
5	5.56	0.70	116.80	4.26	121.07
6	6.73	0.31	219.19	0.93	220.12
7	8.69	1.84	705.62	49.89	755.51
8	7.38	1.63	757.72	59.25	816.97
9	9.36	2.13	279.05	18.51	297.56
10	6.48	1.03	197.67	10.26	207.93
11	11.53	1.83	85.35	2.74	88.10
12	7.84	0.84	61.12	1.34	62.46
13	-2.66	-1.03	85.95	10.95	96.90
14	-2.65	-0.83	453.32	46.54	499.86
15	-2.66	-1.01	151.68	18.85	170.52
16	20.62	7.37	666.99	88.97	755.96
17	22.82	9.13	595.68	59.37	655.05
18	14.24	2.82	217.81	16.91	234.72
19	9.99	3.16	239.76	30.02	269.78
20	8.37	2.79	133.98	14.80	148.79
21	18.77	4.40	313.41	29.06	342.47
22	7.59	1.26	174.59	0.00	174.59
23	13.36	5.88	155.88	81.64	237.52
24	11.07	2.61	127.32	12.00	139.32
Total			6,084.04	611.46	6,695.50

As for the IEEE-30 bus test system, the first advantage of LRMC-AC is allocation of reactive power cost. As a result, it can cover more revenue than LRMC-DC method, which can be seen from Figure 5.10. The total annual capital cost required to be covered is £11,080.32k. LRMC-AC can cover 60.4% of total capital cost, which is 6% more than LRMC-DC.

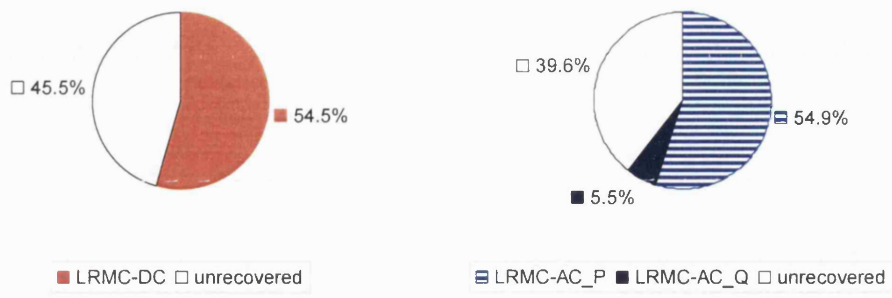


Figure 5.10: LRMC-DC and LRMC-AC cost recovery on distribution test system

In the current charging statement of the WPD company, the final tariff is evaluated from the yardstick calculation, which is a fixed price for each voltage level [Wpd 2006a]. In the LRMC results, either paying or rewarding by the distribution company is distinguished from the usage of the network, regardless of the customers' voltage level. Because demand at nodes 1, 2, and 4 have the shortest distance to generator-connected nodes 13-15, they have lower prices than other loads. Contrarily, demand at nodes 16 and 17 get the highest prices because they use more facilities than others, which also indicate that these sites will attract future embedded generators with most benefits. Therefore, the locational signal dominates the price signals, as seen in Figure 5.11, which emphasizes the observations from the previous IEEE test system.

From the reactive power prices of LRMC-AC in Figure 5.11, it also shows that the rural customers have higher reactive power prices, due to voltage drop considerations along the long-distance lines, such as for nodes 16, 17, 21, and 23. It truly reflects the natural characteristics of the distribution network. Overall, both the LRMC-DC and LRMC-AC pricing methods can produce reasonable results on the distribution network. Additionally, the LRMC-AC pricing method has the advantage of reactive power pricing.

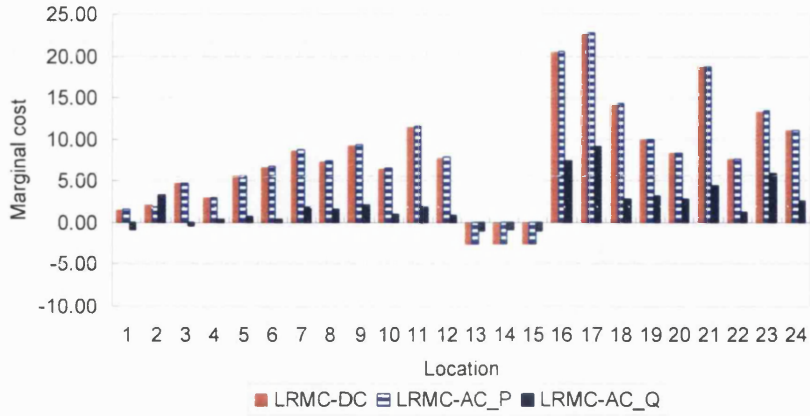


Figure 5.11: LRMC-DC and LRMC-AC Price comparison on the distribution test system

5.5 Chapter Conclusion

In this chapter, LRMC-DC are presented and tested on the IEEE standard test system and the practical distribution test system. With the locational signal, the results of distribution test system show a reasonable pattern which corresponds to the NGC official TNUoS tariffs, as shown in Appendix A-3. Additionally, the different reactive power pricing methods are introduced to extend LRMC-DC into LRMC-AC. Besides the *perpendicular approach*, the *arc approach* is another novel method to allocate the reactive power cost. They are named from the different lines made in the triangle relationship between apparent power and real/reactive power to define the reactive power cost. The *perpendicular approach* decides the unit cost of real and reactive power according to the power factor. The *arc approach* keeps the same real power price as LRMC-DC and allocates the price difference between the apparent power and the real power to the reactive power, which is more straightforward to explain the reactive power price to network users. The allocation of reactive power cost encourages the network users to operate at a better power factor as they attempt to minimise their network charges. For the network owner, the prices covered by reactive power can also bring locational signals to install future reactive power compensation devices. Overall, LRMC-AC demonstrates a more competitive result than LRMC-DC on capital cost recovery, and recognition of the reactive power.

Chapter 6

LRMC with Network Utilisation Consideration (LRMC-Util%)

The LRMC-AC pricing methodology does not consider network utilisation. Hence it can not truly reflect the network investment. To overcome the deficiency of LRMC-AC, LRMC with network utilisation consideration (LRMC-Util%) is introduced and formulated. LRMC-Util% is tested on the IEEE-30 bus test system and the distribution test system. Then three designed case studies are presented to analysis the difference between LRMC-AC and LRMC-Uitl% pricing methodologies. All three case studies are demonstrated on the IEEE-30 bus test system. Different scenarios testify that LRMC-Util% can provide greater benefits for the network owner and network users with the efficient network investment price signal.

6.1 Chapter Introduction

In Chapter 5, the LRMC-AC pricing methodology shows its applicability to distributions systems. It can provide clear locational signals and distinguish reactive power consumption of different customers. Additionally, the marginal cost mechanism reflects the economic effect of the network pricing scheme. However, neither LRMC-DC nor LRMC-AC considers the future network investment. In the asset evaluation process, the asset unit cost is based on its capital cost, capacity, and annuity factor, as described in Equation 5.7. The capital cost and capacity are fixed once the asset is installed. The annuity factor is based on the rate of return applicable for the price control period (currently 6.9%) over a 40-year asset life. So the asset unit cost is isolated from its physical constraints. It keeps the same value even if reinforcement is already needed.

Practically, in the asset management, the asset life is monitored and inspected, influenced by asset cost, risk, performance etc. Here some aspects of the asset life and asset utilisation are discussed, as a way of introducing the following network pricing method. Most transmission and distribution assets can exceed their designed lifespan. For example, as shown in Figure 6.1 for a utility company in the United States [Bro 2005], thirty percent of this utility's poles are older than their 40-year economic lifetime, and fifty percent of this utility's poles are more than 30 years old. It often seems wasteful to replace old equipment before it fails, but the possibility of drastic increases in equipment failures is also unacceptable from both financial and system performance perspectives.

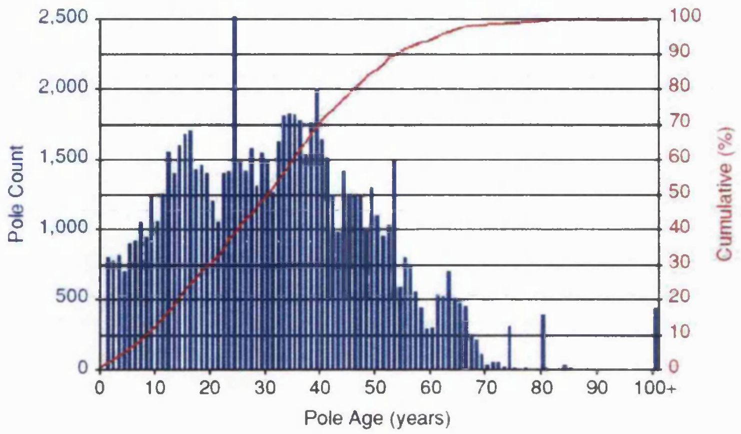


Figure 6.1: Poles' age [Bro 2005]

The asset utilisation of this utility company is illustrated in Figure 6.2. On average, the distribution transformers of this utility are loaded less than fifty percent of the nameplate rating at the peak loading time. Better asset utilisation could help this utility to reduce capital spending and increase returns on its asset base.

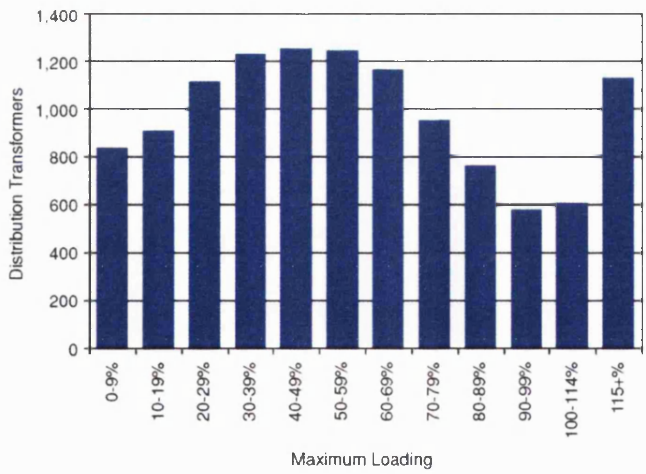


Figure 6.2: Distribution transformer loading condition [Bro 2005]

Regardless of the asset investment consideration, LRMC-AC pricing methodology has a fundamental problem. The following is an example of how drawback occurs with the different lines' investment.

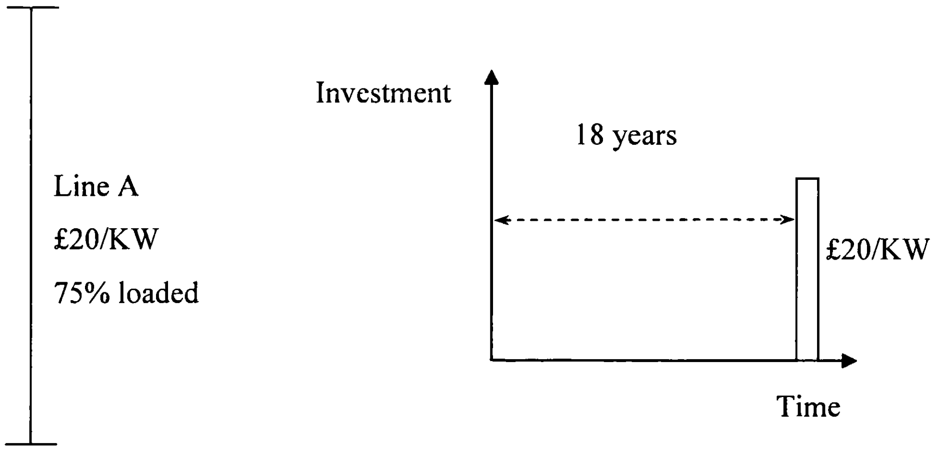


Figure 6.3: Line A lightly loaded

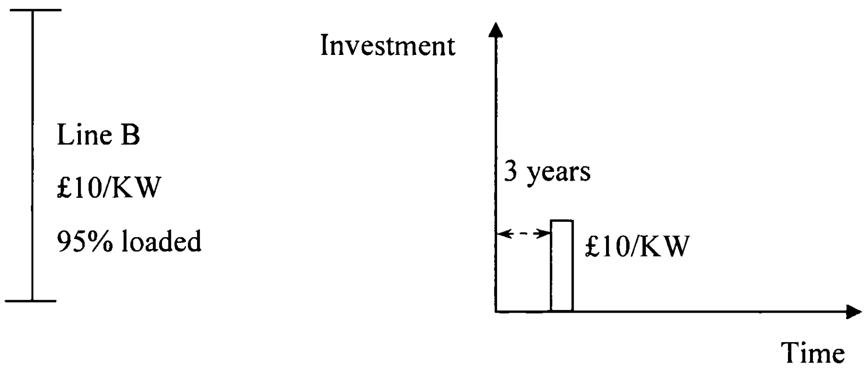


Figure 6.4: Line B heavily loaded

There are two lines A and B, as shown in Figure 6.3 and 6.4, it assumes the load growth rate is 1.6%, and the discount rate is 6.9%. Figure 6.3 shows line A, which is

75% loaded. With the assumed fixed load growth rate, the investment will be realized after 18 years. Using Equation 5.4, the present value of £20/KW after 18 years is £6/KW. Figure 6.4 shows line B with 95% loading. The investment will be realized after 3 years. The present value of £10/KW after 3 years is £8/KW.

In LRMC-AC pricing methodology, the unit cost of line A (£20/KW) is higher than the unit cost of line B (£10/KW). But from the above analysis, line B does not have enough capacity, and the investment is needed in a short period with a higher cost (£8/KW) than line A (£6/KW). With the utilisation consideration, the unit cost of line B should be modified, and proposed to be higher than the unit cost of line A.

Network assets can operate for more than their designed lifetime, and can also be reinforced or replaced during their lifetime. Better network utilisation can delay the network investment. Taking these factors into account, the unit cost should reflect the future network investment, instead of being a fixed value. Therefore, a novel concept of LRMC with utilisation consideration (LRMC-util%) is proposed by the University of Bath [Li 2005, Wpd 2006c], which is a joint work that the author is taking an important part in. LRMC-Util% pricing methodology aims to evaluate the costs of network assets based on their utilisation, and bring the potential future investment into account. The investment occurs when the network facilities exhaust their lifespan, or the network facilities are close to being fully loaded, or both.

In LRMC-Util% methodology, asset utilisation is introduced to adjust the discount factor. It means that the network asset life can be extended or discounted by its loading condition according to whether its usage level is low or high. Based on the utilisation change, the cost of closer reinforcement can be integrated into the higher annuity cost of heavily loaded assets. Thus, the network asset cost is decided by the capacity (for circuits and transformers), distance (for circuits) and the portion of future investment. In addition, combined with the *arc approach* of reactive power allocation, the LRMC-Util% methodology demonstrates an allocation method with reactive power pricing. The customers with a poor power factor are charged by DNOs to maintain the network security.

6.2 LRMC with Network Utilisation Consideration (LRMC-Util%)

6.2.1 University of Bath Model

The University of Bath model seeks to reflect the impact on the advancement or deferral of future investment in network components, as a result of a unit injection or withdrawal of generation or load at each study node. For a component, that is affected there will be a cost associated with accelerating investment, or a benefit associated with the deferral of investment. Depending upon the discount rate that is employed, and the magnitude of the expenditure, which could be a function of transformer capacity or circuit length, the LRMC can be calculated [Li 2005b].

1. Determining When Investment Will Occur in the Future

Given a generic load growth rate, the number of years it takes to grow from a network component l current loading condition to its capacity, can be determined as follows:

$$C_l = D_l \cdot (1+r)^{nyr_l} \tag{6.1}$$

Where,

C_l: the capacity of the network component l,

D_l: the power flow of the network component l,

r: a given load growth rate of a certain network, *nyr*: the number of the years.

Because the utilisation of the network component l can be described as

$$util_l\% = \frac{D_l}{C_l}$$

Taking the logarithm of both sides of above equation, the number of years can be described as:

$$nyr_l = -\frac{\lg util_l\%}{\lg(1+r)} \qquad (6.2)$$

2. Present Value (PV) of Future Investment

Since the concept of present value (PV) has been explained in the asset cost evaluation section of Chapter 5, the future investment can be discounted back to PV according to after how many years the investment will occur.

$$PV_l = \frac{Asset_l}{(1+d)^{nyr_l}} \qquad (6.3)$$

Where,

d: the discount rate (expected rate of return).

If the asset is a long circuit, then the future investment will be high; if the circuit is short, then the investment will be low.

3. Cost Associated with Marginal Injection

A unit power n is injected into a certain node N to demonstrate the base load profile with a marginal increase. When investment will occur in the future, the number of years of the network component l can be determined:

$$C_l = D_{l,new} \cdot (1+r)^{nyr_{l,new}} \qquad (6.4)$$

If

$$util_{l,new}\% = \frac{D_{l,new}}{C_l},$$

then

$$nyr_{l,new'} = -\frac{\lg util_{l,new'}\%}{\lg(1+r)} \tag{6.5}$$

So,

$$PV_{l,new'} = \frac{Asset_l}{(1+d)^{nyr_{l,new'}}} \tag{6.6}$$

4. Calculating LRMC Cost

The final cost is the total difference between the PV and the new PV. A heavily loaded part of network needs investment in a short period, which results in a big difference between the present value and new present value.

$$MC_N = \frac{\sum_{l=1}^{L}\left(PV_{l,new'} - PV_l\right)}{n} \tag{6.7}$$

Where,

L: the total number of network assets.

Repeating steps 3 and 4, the marginal costs of all the study nodes can be calculated.

6.2.2 Formulation of LRMC-Util%

Based on the developed *arc approach* of reactive power methodology in Chapter 5, the LRMC-Util% can formulated as below.

1. Mapping Utilisation of Asset into Years

Given a generic load growth rate in power sector [Wwf 2006], which is 1.6% taken from private project meetings for this research, the number of years it takes to grow from a network asset l current loading condition to its capacity can be determined.

$$C_l = DP_l \cdot (1+r)^{nyrP_l} \tag{6.8}$$

$$C_l = DS \cdot (1+r)^{nyrS_l} \tag{6.9}$$

Where,

C_l: the capacity of the network component l,

DP_l: the magnitude of real power flow of the network component l,

DS_l: the magnitude of apparent power flow of the network component l,

$nyrP$: the number of the years based on real power,

$nyrS$: the number of the years based on apparent power.

Because the utilisation of the network component l can be described as

$$utilP_l\% = \frac{DP_l}{C_l} \qquad utilS_l\% = \frac{DS_l}{C_l}$$

Taking the logarithm of both sides of above equation, the number of years can be described as

$$nyrP_l = -\frac{\lg utilP_l\%}{\lg(1+r)} \tag{6.10}$$

$$nyrS_l = -\frac{\lg utilS_l\%}{\lg(1+r)} \tag{6.11}$$

2. Determining Present Value (PV) of Future Investment

The future investment can be discounted back to the present value (PV) according to after how many years the investment will occur.

$$PVP_l = \frac{Asset_l}{(1+d)^{nyrP_l}} \tag{6.12}$$

$$PVS_l = \frac{Asset_l}{(1+d)^{nyrS_l}} \tag{6.13}$$

$$PVQ_l = PVS_l - PVP_l \tag{6.14}$$

Where,

PVP_l: PV based on real power of the network component l,

d: the discount rate (expected rate of return).

PVS_l: PV based on apparent power flow of the network component l,

PVQ_l: PV based on reactive power of the network component l.

3. Cost associated with marginal injection

A unit power n (MW) + n (MVAR) is injected into a certain node N to demonstrate the base load profile with a marginal increase. When investment will occur in the future, the number of year of the network component l can be determined:

$$PVP_{l,new} = \frac{Asset_l}{(1+d)^{nyrP_{l,new}}} \tag{6.15}$$

$$PVS_{l,new} = \frac{Asset_l}{(1+d)^{nyrS_{l,new}}} \tag{6.16}$$

$$PVQ_{l,new} = PVS_{l,new} - PVP_{l,new} \tag{6.17}$$

4. Determining LRMC cost

The final cost is the total difference between the present value and new present value. A heavily loaded part of network needs investment in a short period, which results in a big difference between the present value and new present value.

$$MCP_N = \frac{\sum_{l=1}^{L} (PVP_{l,new} - PVP_l)}{n} \tag{6.18}$$

$$MCQ_N = \frac{\sum_{l=1}^{L} (PVQ_{l,new} - PVQ_l)}{n} \tag{6.19}$$

Repeating steps 3 and 4, the marginal costs of all the study nodes can be calculated.

6.2.3 Utilisation with Security Factor

From the network planning point of view, the 33KV and above network is generally designed to meet *n-1* contingency, which is the network security standard [Wpd 2006c]. If the security index is defined as the number of the lines connected between two busbars, then the security factor is calculated as:

$$SecurityFactor = \frac{1}{SecurityIndex - 1} \cdot SecurityIndex \tag{6.20}$$

Based on the defined security index and security factor, the minimum and maximum utilisation can be calculated as:

$$CriticalUtil\% = \frac{SecurityIndex - 2}{SecurityIndex - 1} \cdot 96\% \tag{6.21}$$

$$MaxUtil\% = \frac{1}{SecurityIndex} \cdot (SecurityIndex - 1) \tag{6.22}$$

For example in Figure 6.5, if there are three lines connected between two nodes, the security index is 2. Using Equation 6.20, the security factor is 2. To meet the *n-1* contingency, each line's maximum utilisation should be half of the proposed power flow between bus 1 and bus 2. To explain the critical utilisation, the case of security index 3 is presented. If the security index is 3, security factor is 1.5 and line's maximum utilisation is 66.7%. Because the range below 50% has been covered by index 2, the minimum or critical utilisation of lines with security index 3 is 50% * 96% (* means multiply). 4% is an approximate overloaded percentage of lines, which is consulted in the private project meetings with Western Power Distribution (WPD) Company.

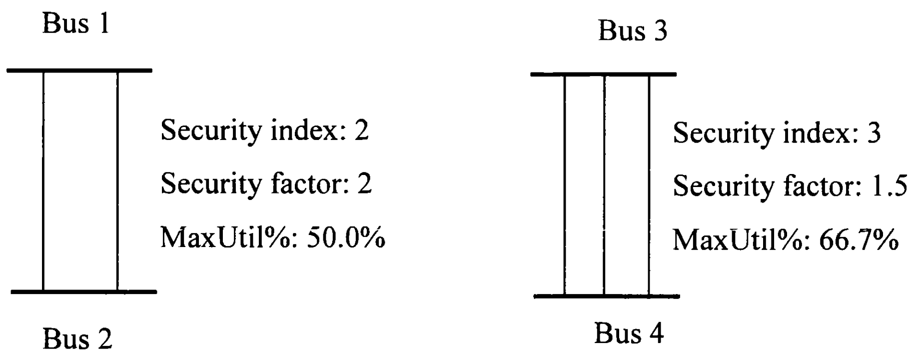


Figure 6.5: Security index 2 and 3

In the LRMC-Util% calculation, there should be a way to use utilisation to estimate the security factor, then adjust the security index according to the looking up Table 6.1.

Table 6.1: Security index looking up table

Security index	Security factor	Critical Util%	Maximum Util%
1	1.00	87.5% * 96% <	< 100%
2	2.00	-	< 50.0%
3	1.50	50.0% * 96% <	< 66.7%
4	1.33	66.7% * 96% <	< 75.0%
5	1.25	75.0% * 96% <	< 80.0%
6	1.20	80.0% * 96% <	< 83.3%
7	1.17	83.3% * 96% <	< 85.7%
8	1.14	85.7% * 96% <	< 87.5%

If the utilisation of a facility is in a certain range between critical util% and maximum util%, the security index and security factor should be changed into the corresponding level.

6.3 Results and Analysis

6.3.1 IEEE-30 Test system

The IEEE-30 bus test system has been introduced in Section 5.4.1 of Chapter 5 and Appendix B-1.

Table 6.2 shows the results of the LRMC-Util% method. The marginal cost is for demand, so the cost of generation will be the negative equivalent of the values in the table. In Figure 6.6, the nodal marginal costs of LRMC-Util% are plotted.

Table 6.2: LRMC-Util% results on IEEE-30 bus test system

	Marginal Cost (£/unit/Yr) for Demand		Cost Recovered (£000/Yr)		
NO.	P(£/KW/Yr)	Q(£/KVAr/Yr)	P(£000/Yr)	Q(£000/Yr)	Total(£000/Yr)
2	17.32	-0.93	-316.88	34.65	-282.23
3	13.48	0.80	32.34	0.96	33.31
4	17.56	1.01	133.49	1.62	135.10
5	28.80	-1.03	2,712.77	18.61	2,731.38
6	31.76	0.06	0.00	0.00	0.00
7	31.20	-0.23	711.38	-2.55	708.83
8	32.83	-0.10	984.99	0.74	985.73
9	32.28	0.84	0.00	0.00	0.00
10	32.80	1.55	190.23	3.10	193.33
11	32.28	0.65	0.00	-10.56	-10.56
12	15.71	-0.71	175.96	-5.34	170.62
13	15.78	-0.76	0.00	8.00	8.00
14	19.96	-0.16	123.72	-0.25	123.47
15	21.54	-0.15	176.61	-0.37	176.24
16	22.72	0.10	79.53	0.18	79.71
17	31.69	1.81	285.19	10.50	295.70
18	37.63	4.30	120.41	3.87	124.27
19	38.47	4.09	365.45	13.89	379.34
20	37.54	3.54	82.58	2.48	85.06
21	38.36	3.60	671.30	40.33	711.63
22	38.20	3.56	0.00	0.00	0.00
23	42.30	7.23	135.35	11.56	146.91
24	41.42	5.31	360.31	35.60	395.91
25	39.28	2.86	0.00	0.00	0.00
26	41.10	3.23	143.85	7.42	151.27
27	36.52	1.06	0.00	0.00	0.00
28	32.84	0.24	0.00	0.00	0.00
29	40.29	1.69	96.71	1.52	98.23
30	42.18	1.96	447.10	3.71	450.81
Total			7,712.38	179.69	7,892.07

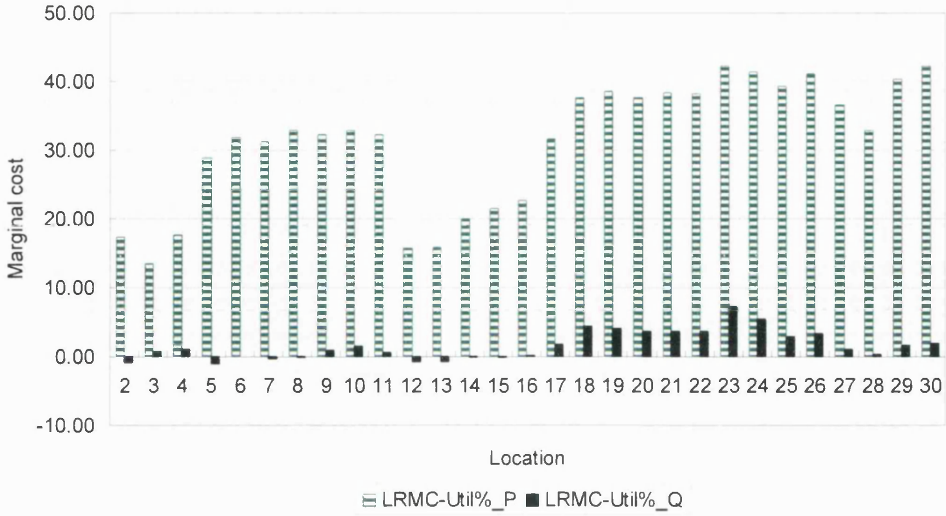


Figure 6.6: LRMC-Util% results on IEEE-30 bus test system

From the connection map in Figure 5.5 and load flow results in Appendix B-1, the nodes 2-4 and nodes 12-16 are strongly connected, and sited in the lightly loaded network, so the marginal costs are lower than for others. Node 28 is connected with other 132KV nodes 6 and 8, so they tend to have similar prices. Because of the electrical connections, all the other 132KV nodes and 33KV nodes are split into two groups. Due to the extensive use of the network, 33KV nodes have higher prices than 132KV nodes.

Since the results of LRMC-AC pricing methodologies are presented in Chapter 5, the results are reorganized and put together with LRMC-Util% to form a basic image regarding the price signals. Figure 6.7 shows the cost recovery from LRMC-AC and LRMC-Util% pricing methodologies on the IEEE-30 bus test system. Due to the existing network loading level, LRMC-Util% (58.9%) can recover more total capital cost than LRMC-AC (45.5%).

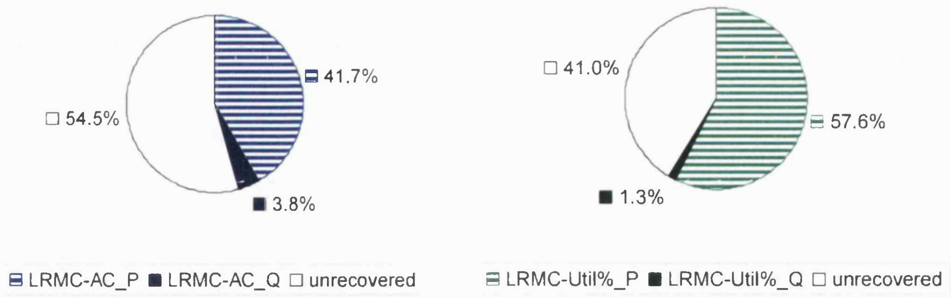


Figure 6.7: LRMC-AC and LRMC-Util% cost recovery on IEEE-30 bus test system

Figure 6.8 compares the nodal real and reactive power price for demand between LRMC-AC and LRMC-Util%.

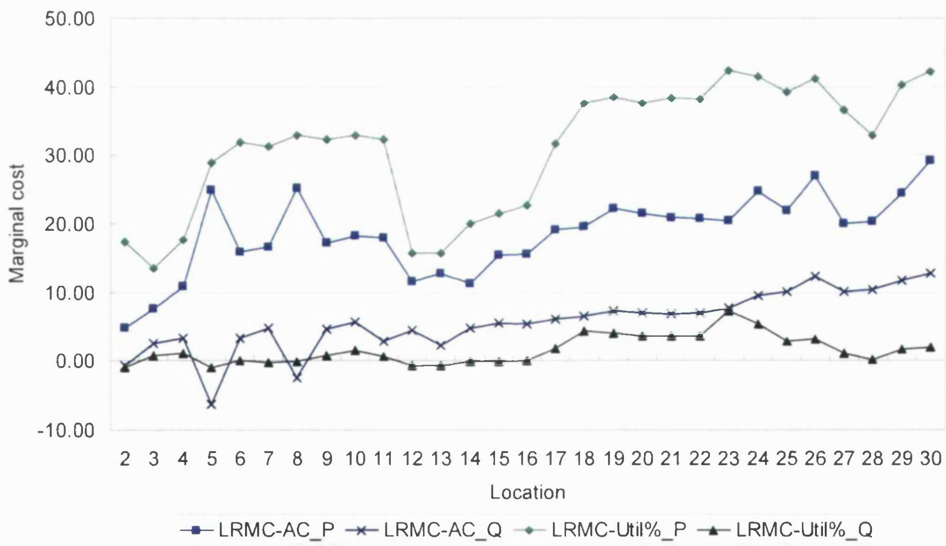


Figure 6.8: LRMC-AC and LRMC-Util% price comparison on IEEE-30 bus test system

Firstly, both LRMC-AC and LRMC-Util% distinguish the costs at different locations. The locational signal of LRMC-AC is based on the network assets' cost. So if the node is allocated far way from the slack bus and uses long-distance network facilities, it will be charged at a higher price, such as nodes 5 and 8. In the LRMC-Util% method, the locational signal is based on the network assets' cost and their utilisation, so the prices tend to group into zones. For example, because the utilisation of same voltage level is similar, most 132 KV nodes (nodes 5-8) have the similar prices, so do most 33KV nodes (nodes 18-30). Based on the concept of zonal tariffs using by Nation Grid Company (NGC), as shown in Chapter 3, when the nodal prices are close to nearby nodes, it is more convenient to calculate zonal prices using LRMC-Util% than LRMC-AC.

Secondly, both methods set the prices for reactive power. Because the synchronous condensers inject reactive power at nodes 5, 8, 11, and 13, the LRMC-AC_Q at these nodes are notably less than at other nodes. In the LRMC-Util% method, the reactive prices are generally less than in the LRMC-AC method. The reason for this is that real power dominates the network's utilisation. The capacity of most network facilities is occupied by the real power. Thus, following Equation 6.12-6.19, LRMC-Util% tends to allocate more costs to real power, due to its major contribution of line flow.

6.3.2 Distribution Test System

The Distribution test system has been introduced in Section 5.4.2 of Chapter 5 and Appendix B-2.

Table 6.3 shows the results of LRMC-Util% method on the distribution test system. The marginal cost shown in the table is for demand. In Figure 6.9, the nodal marginal costs of LRMC-Util% are plotted.

Table 6.3: LRMC-Util% results on distribution test system

	Marginal Cost (£/unit/Yr) for Demand		Cost Recovered (£000/Yr)		
NO.	P(£/KW/Yr)	Q(£/KVAr/Yr)	P(£000/Yr)	Q(£000/Yr)	Total(£000/Yr)
1	-3.17	-0.88	-110.15	-3.05	-113.20
2	-0.58	1.31	-14.36	22.79	8.42
3	9.61	2.04	385.46	13.46	398.92
4	-4.36	-0.33	-90.33	-2.67	-93.01
5	0.72	0.45	15.08	2.75	17.83
6	8.68	1.73	282.53	5.20	287.74
7	9.56	2.64	775.67	71.41	847.09
8	8.59	2.49	881.28	90.32	971.60
9	8.67	2.35	258.49	20.46	278.95
10	7.43	2.26	226.46	22.57	249.03
11	5.17	1.02	38.28	1.53	39.81
12	3.53	0.70	27.53	1.12	28.64
13	-9.03	-1.29	291.57	13.74	305.31
14	-8.99	-1.04	1,537.63	58.62	1,596.25
15	-9.03	-1.26	514.60	23.64	538.24
16	17.08	6.36	552.44	76.72	629.16
17	21.28	8.46	555.41	54.96	610.37
18	6.45	1.72	98.61	10.30	108.90
19	10.44	3.98	250.66	37.82	288.48
20	4.64	1.67	74.18	8.82	83.00
21	7.36	2.06	122.96	13.62	136.58
22	7.31	1.30	168.06	0.00	168.06
23	16.80	7.33	196.07	101.73	297.79
24	3.62	1.31	41.63	6.04	47.67
Total			7,079.75	651.89	7,731.64

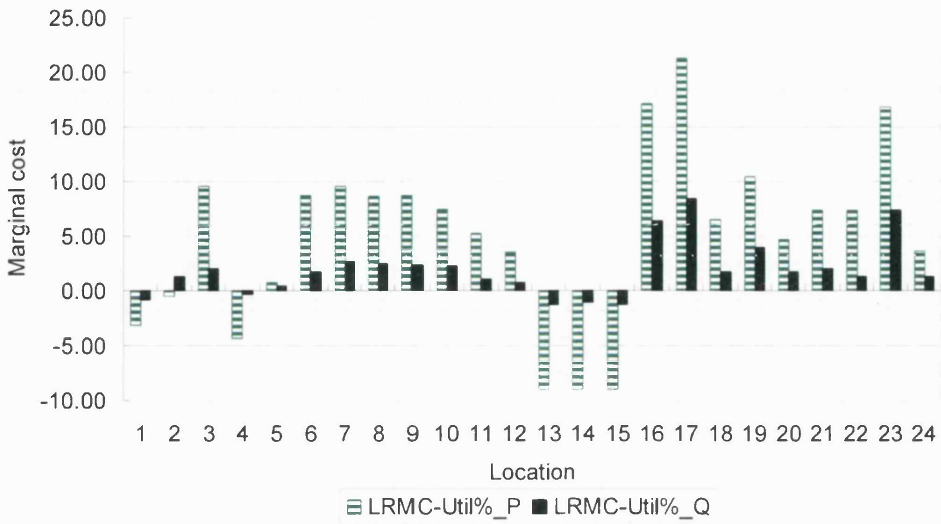


Figure 6.9: LRMC-Util% results on the distribution test system

From the load flow results in Appendix B-2, nodes 13-15 are generator connected and dominated. The generators are charged for their use of network, by the negative equivalent of the values in Table 6.3. Nodes 1 and 4 are close to nodes 13-15, which means they can consume the network generators' output, and encourage the local generation to meet local demand, so they are rewarded for their usages.

Further comparisons with previous results of LRMC-AC pricing methodology in Chapter 5 are presented below. Figure 6.10 shows the cost recovery from the LRMC-AC and LRMC-Util% pricing methodologies on the distribution test system. Due to the network loading level, LRMC-Util% (69.8%) can recover more total capital cost than LRMC-AC (60.4%).

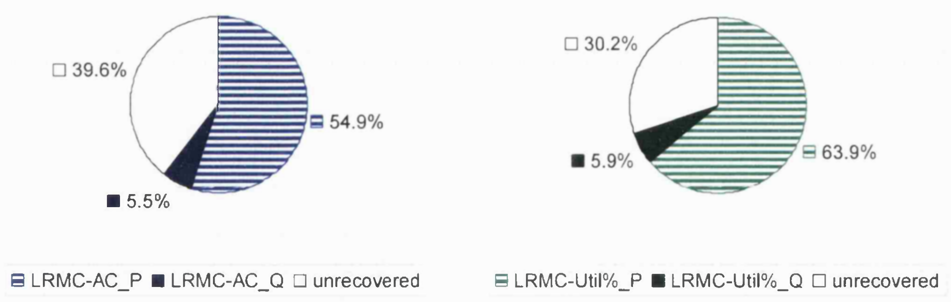


Figure 6.10: LRMC-AC and LRMC-Util% cost recovery on distribution test system

Figure 6.11 compares the nodal price for demand between LRMC-AC and LRMC-Util%.

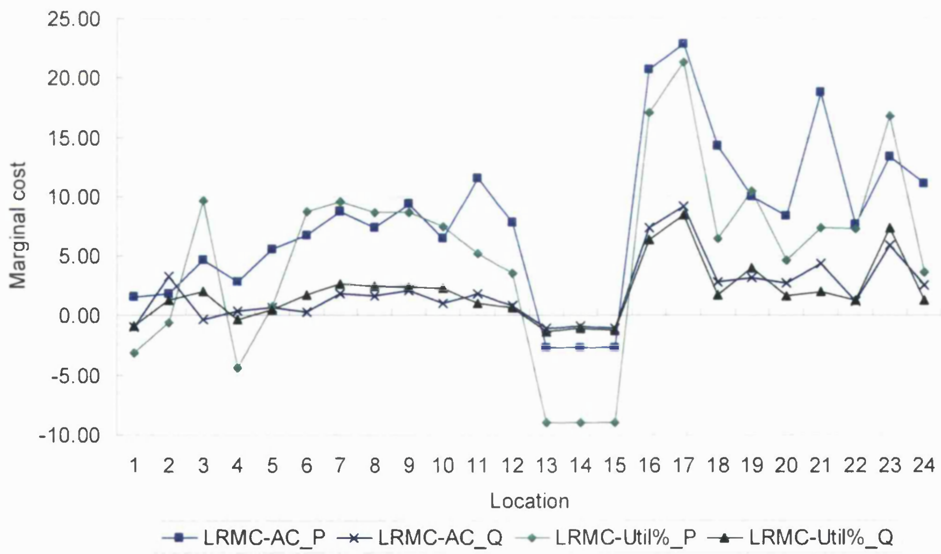


Figure 6.11: LRMC-AC and LRMC-Util% price comparison on distribution test system

Firstly, both LRMC-AC and LRMC-Util% reflect the locational signal. Because nodes 13-15 are highly utilized due to their connection to a large generator plant, they are charged at a lower price for demand by LRMC-Util% than LRMC-AC. It encourages an increase in local demand. Secondly, both methods can set a similar price for reactive power.

Summarizing, from the above two test systems, both LRMC-AC and LRMC-Util% can distinguish the siting and reactive power consumption of customers. The distribution results presented here are in a similar price range when compared with the NGC official TNUoS tariffs (-8£/KW~23£/KW), as shown in Appendix A-3. Additionally, the LRMC_Util% pricing methodology can reflect the use of network more practically than LRMC-AC, so it can recover more capital cost, due to the current loading conditions in both test systems.

6.4 LRMC-AC vs. LRMC-Util%

The concept and application of the LRMC-Util% pricing methodology has highlighted in the above sections. Theoretically, it is an innovative concept in the area of use of network charges. Can LRMC-Util% gain more advantage over the previous LRMC methods for network owners and network users practically? There are a few case studies further comparing LRMC-AC and LRMC-Util%. Case 1 investigates the response of embedded generators' location following the sequential marginal cost price signal. Case 2 investigates the price change according to demand's increment. Case 3 investigates the price change with the network reinforcement.

6.4.1 Case 1: Embedded Generator Response

The case study aims to discover how the different price signals can influence the potential location of embedded generators. It assumes that there are five individual embedded "pseudo" generators planning to connect to the network, one after the other. Each "pseudo" generator assumes operating at 10MW real power injection with 0.95 lagging power factor, which also means it withdraws 3.29MVAR reactive power from the network. Each pseudo generator demonstrates a worst case of operating condition of embedded generators.

Each one of them is trying to locate at the ideal position, where it can obtain the highest possible payment from the network owner. Once the first pseudo embedded generator is connected to the network, the network flow will change, and the nodal marginal cost prices will change. Based on the new set of nodal prices, the following second generator will choose the most profitable location again, and so on. In order to investigate directly the response of the embedded generator with price signals change, the demand change and the network constraints are ignored in this case study.

After each pseudo generator is connected to the network, the nodal price for generator, based on the LRMC-AC pricing method, will change due to the power flow change as shown on the left hand graphs of Figures 6.13-6.16. The negative price means that the generators are rewarded for their injection. The next pseudo generator can then choose the location based on the nodal price. The right hand graphs in Figures 6.12-6.16 show the expected payment from the network owner, if the pseudo generator connects to a certain node, based on the price shown on the left. In the following figures, G1 to G5 represent the first to the fifth pseudo generator.

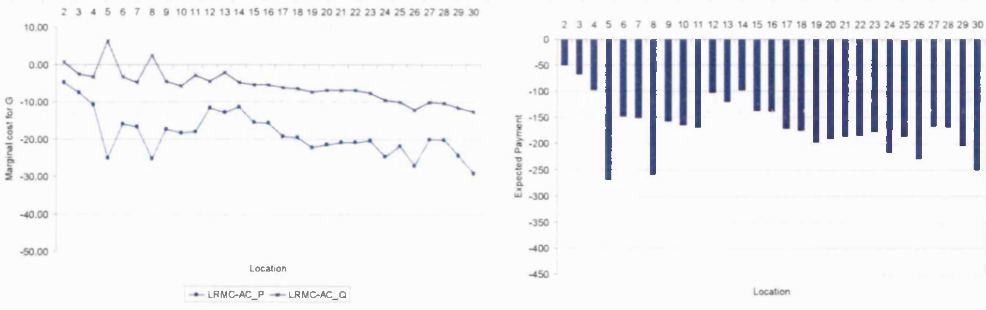


Figure 6.12: G1 at node 5 (LRMC-AC)

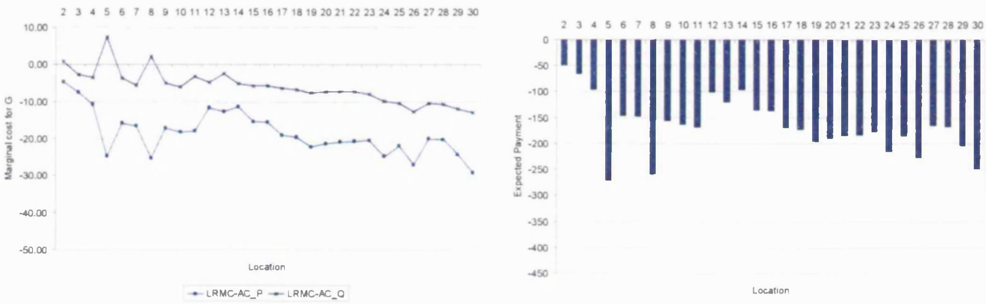


Figure 6.13: G2 at node 5 (LRMC-AC)

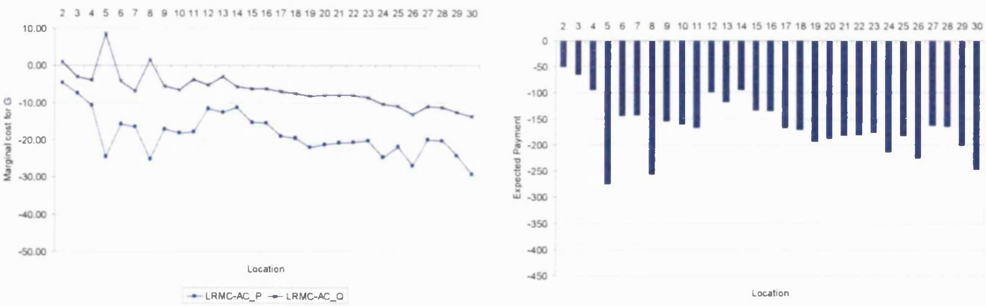


Figure 6.14: G3 at node 5 (LRMC-AC)

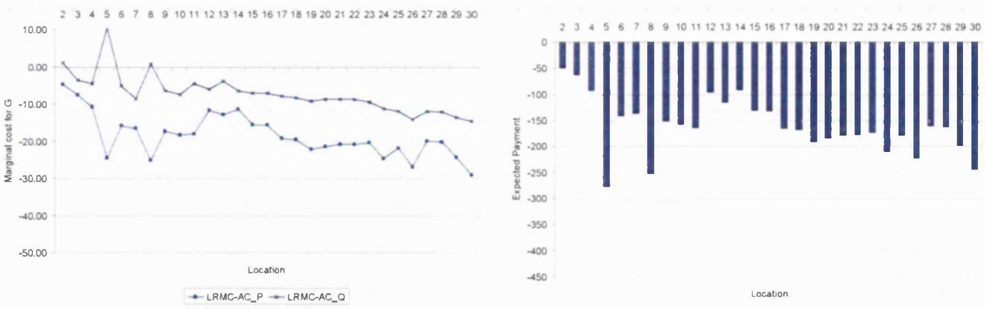


Figure 6.15: G4 at node 5 (LRMC-AC)

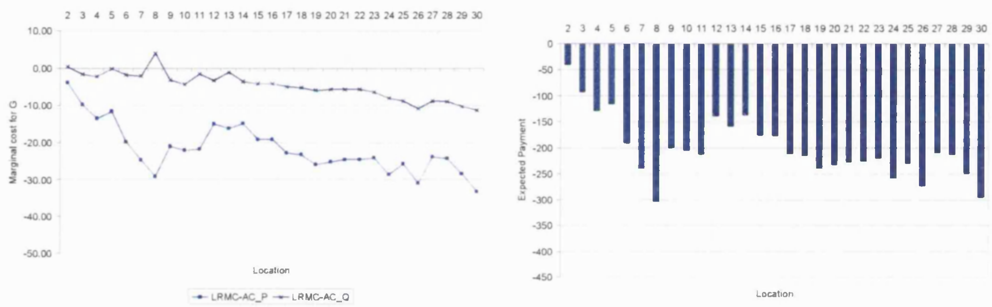


Figure 6.16: G5 at node 8 (LRMC-AC)

Repeat the same process for the LRMC-Util% pricing methodology. Figures 6.17-6.21 show the embedded generator response with the LRMC-Util% method.

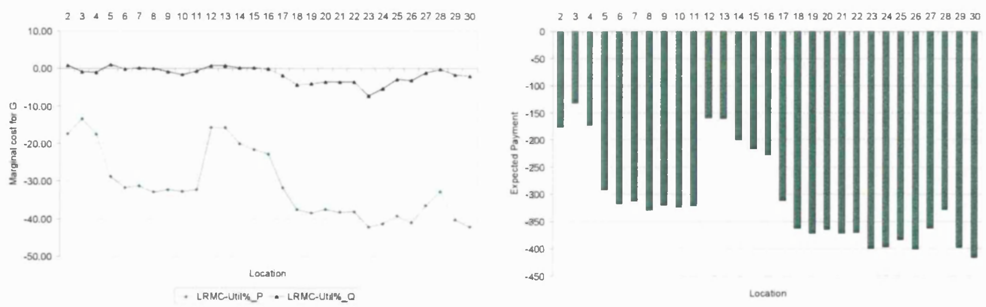


Figure 6.17: G1 at node 30 (LRMC-Util%)

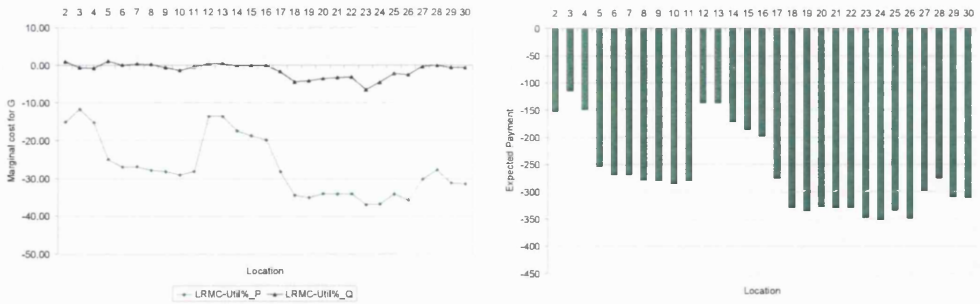


Figure 6.18: G2 at node 24 (LRMC-Util%)

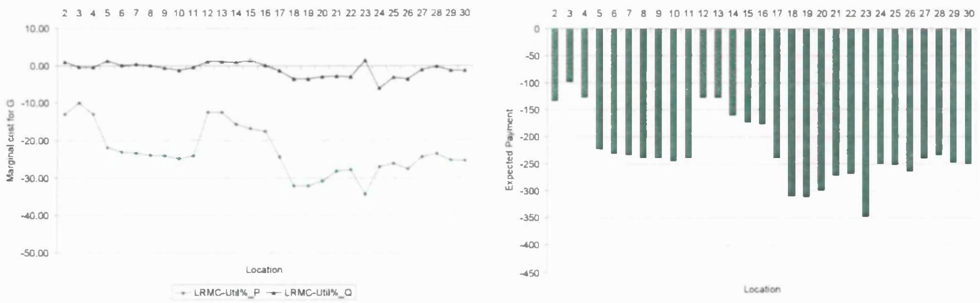


Figure 6.19: G3 at node 23 (LRMC-Util%)

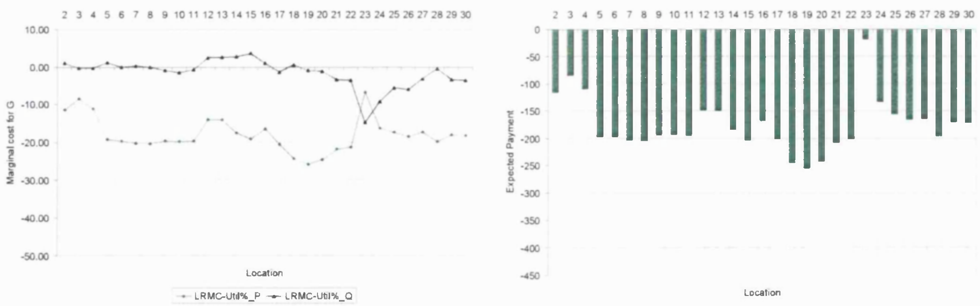


Figure 6.20: G4 at node 19 (LRMC-Util%)

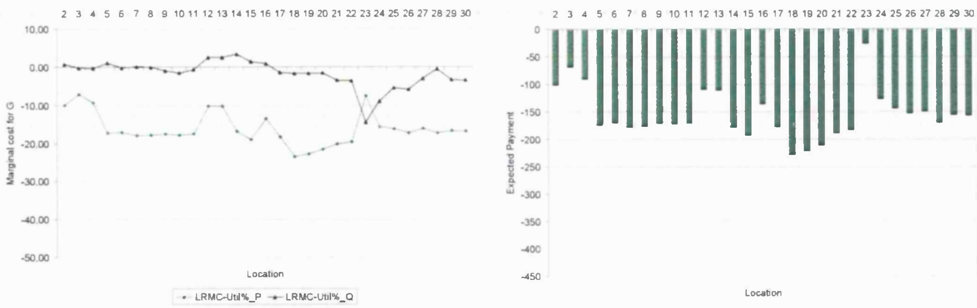


Figure 6.21: G5 at node 18 (LRMC-Util%)

Summarizing the above results into Table 6.4. The suggested location of the pseudo embedded generator using LRMC-AC settles at node 5 from G1 to G4, finally jumping to node 8 due to the power flow direction change in the line 5-7. Using LRMC-Util%, the pseudo embedded generator tends to find the place where the network utilisation can be reduced mostly. The potential location for the next generator is diverted every time, following the nodal prices' change. The advantage can be clearly seen from Figure 6.23, the nodal prices are gradually reduced by the increase of the number of embedded generators. On the contrary, the nodal prices using LRMC-AC, as shown in Figure 6.22, can not provide effective indications to embedded generators.

Table 6.4: Embedded generator response

	Suggested location using LRMC-AC	**Suggested location using LRMC-Util%**
G1	5	30
G2	5	24
G3	5	23
G4	5	19
G5	8	18

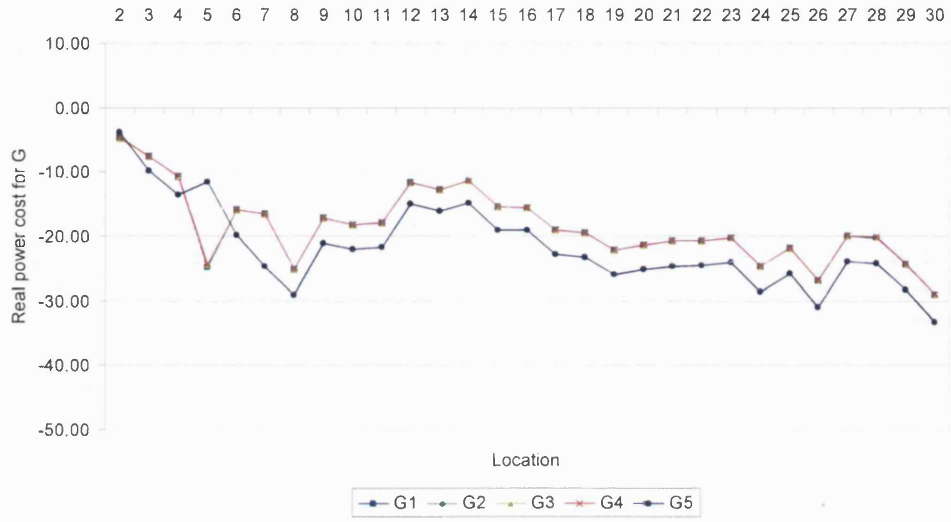


Figure 6.22: Price comparison with G1-G5 (LRMC-AC)

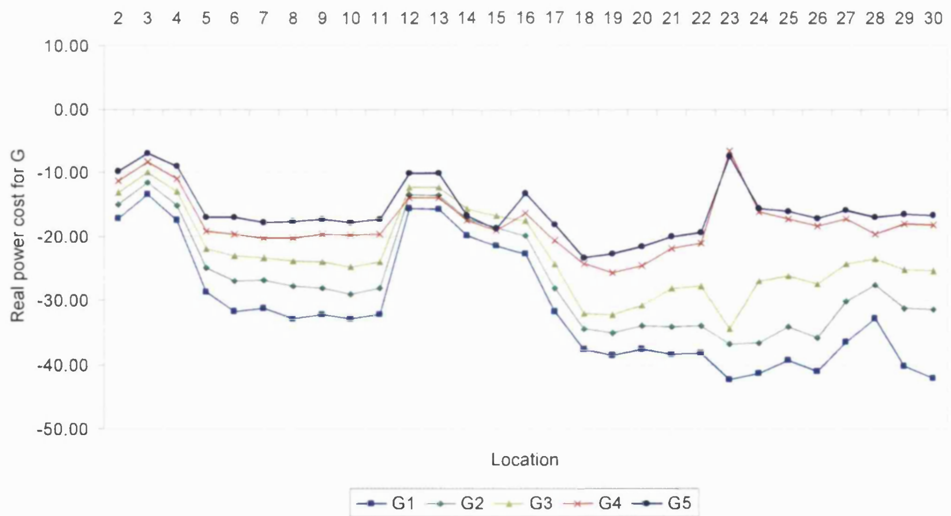


Figure 6.23: Price comparison with G1-G5 (LRMC-Util%)

Figure 6.24 shows the price change at node 30 according to the embedded generator increase. It is clear to see the real power cost change dramatically using LRMC-

Util% than LRMC method. LRMC-Util% can incentivizes generation connection in the areas with highly loaded circuits, and provide a proper price signal for siting embedded generation hence releasing the capacity of highly utilized areas of the network. With more generation connected, the nodal cost for demand reduces, which is the negative equivalent of the values in the figure. Without consideration of utilisation, using LRMC-AC, network price hardly change due to only distance and power travel paths being considered.

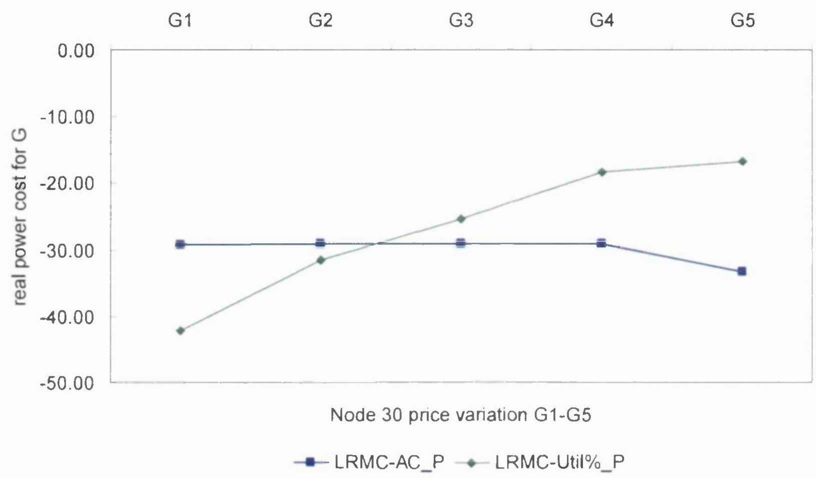


Figure 6.24: Price at node 30 comparison with G1-G5

6.4.2 Case 2: Price Response with Demand Increase

In Case 2, it assumes that the rational average demand growth is 1.6% annually [Wwf 2006]. Without generation change, the case study traces the price response with general demand increase between LRMC-AC and LRMC-Util% pricing methodologies. D1 is the original load profile, and D2 is 1.6% bigger than D1, which means demand at each connected node will rise by 1.6%. The price comparisons of D1-D4, which assume the next three years' demand increase, including the original load profile D1, are shown in Figures 6.25 and 6.26. Figure 6.27 compares the price variation of node 30 with D1-D4.

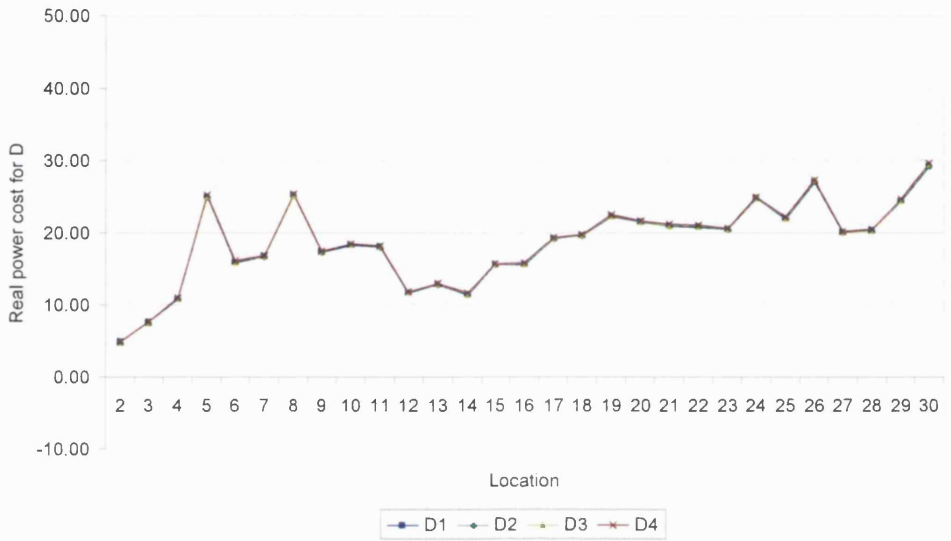


Figure 6.25: Price comparison with D1-D4 (LRMC-AC)

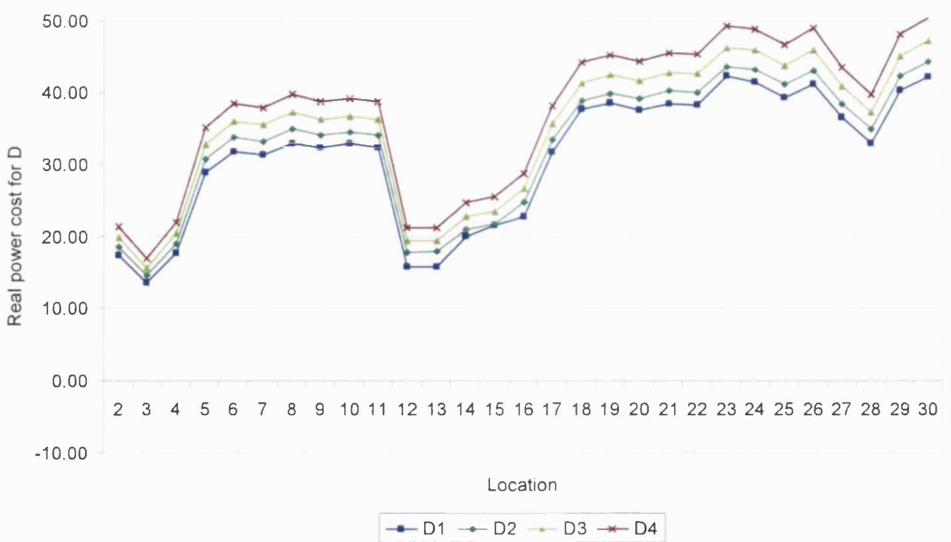


Figure 6.26: Price comparison with D1-D4 (LRMC-Util%)

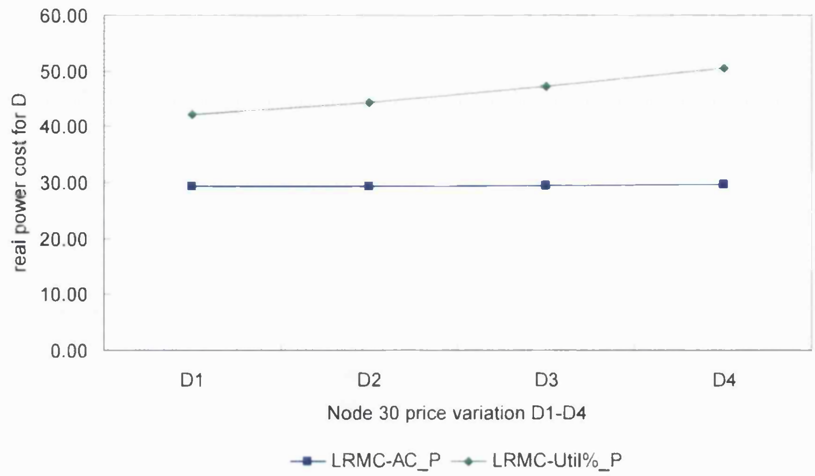


Figure 6.27: Price at node 30 comparison with D1-D4

From Figure 6.25, using LRMC-AC, both real and reactive power prices are hardly changed. This is because the asset unit costs are kept the same. With LRMC-Util%, shown in Figure 6.26, the nodal prices increase following the demand growth, due to the growth in utilisation of the network. By truly reflecting the extended use of network with the utilisation consideration, the cost variation using LRMC-Util% is more sensitive in response to demand change than that using LRMC-AC, as shown in Figure 6.27. The benefit of the LRMC-Util% pricing method is demonstrated in the cost recovery shown in Figures 6.28-6.31. LRMC-Util% can reflect the increase of the nodal prices with demand growth, but LRMC-AC can not.

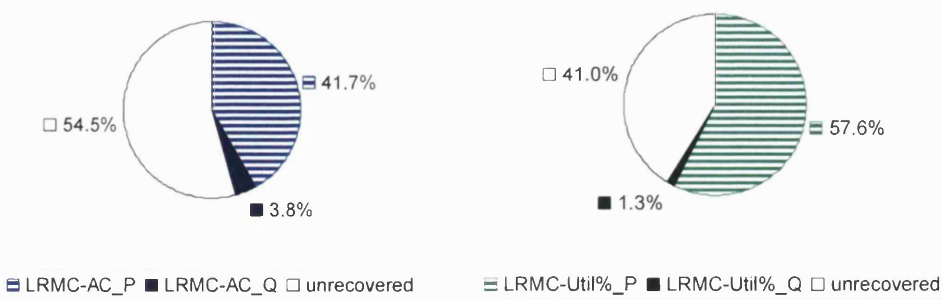


Figure 6.28: D1 cost recovery pattern

Figure 6.29: D2 cost recovery pattern

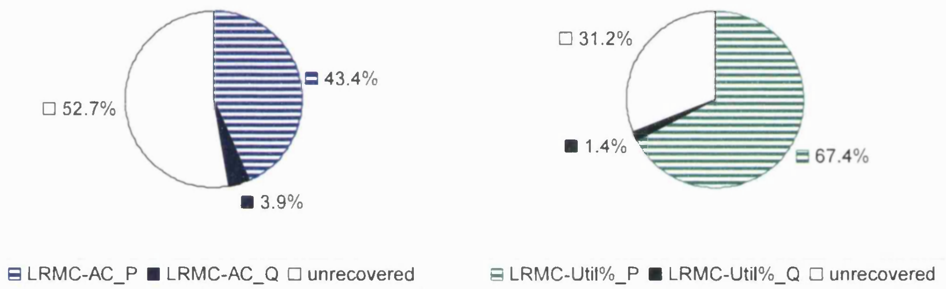


Figure 6.30: D3 cost recovery pattern

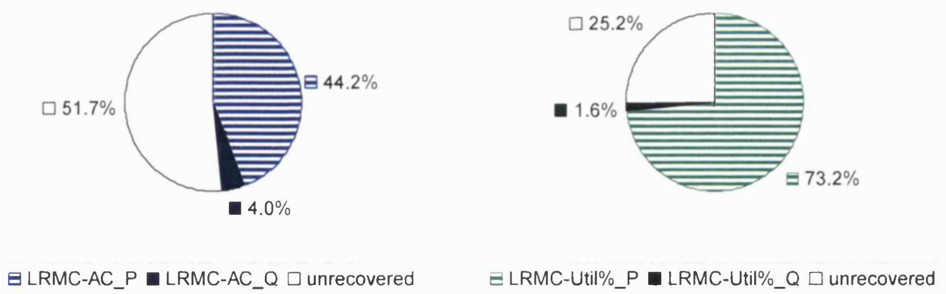


Figure 6.31: D4 cost recovery pattern

6.4.3 Case 3: Price Response with Network Reinforcement

On the IEEE-30 bus test system, there are two lines connected to slack bus 1. Compared with the utilisation (29%) of the line between node 1 and node 3, the other line between node 1 and node 2 is highly loaded (utilisation=42.9%) with the security consideration, as shown in Appendix B-1. In Case 4, a line, the same as the original one, is added between node 1 and node 2. Case 4 is proposed to test the price response with network line reinforcement. The price results of LRMC-AC and LRMC-Util% pricing methodologies are shown in Figures 6.32 and 6.33.

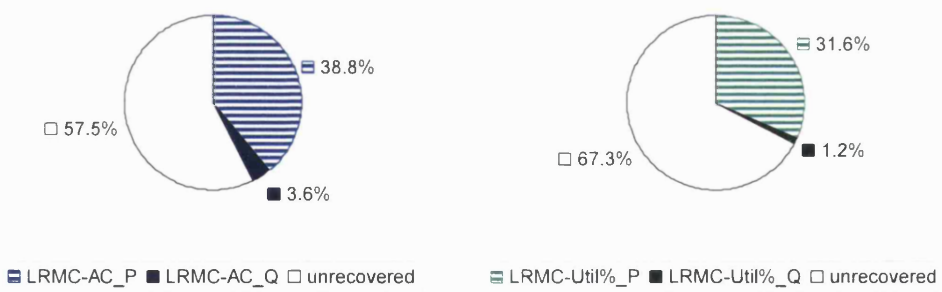


Figure 6.32: LRMC-AC and LRMC-Util% cost recovery on reinforcement IEEE-30 bus test system

Compared with the original case in Figure 6.7, the cost recovery by LRMC-Util% is significantly reduced from 58.9% to 32.8%, due to the utilisation decrease under the line reinforcement. Because the reinforcement line is the same as the existing one, the asset unit cost does not change after the investment in the LRMC-AC pricing method. The cost recovery by LRMC-AC is almost keeping the same around 45%.

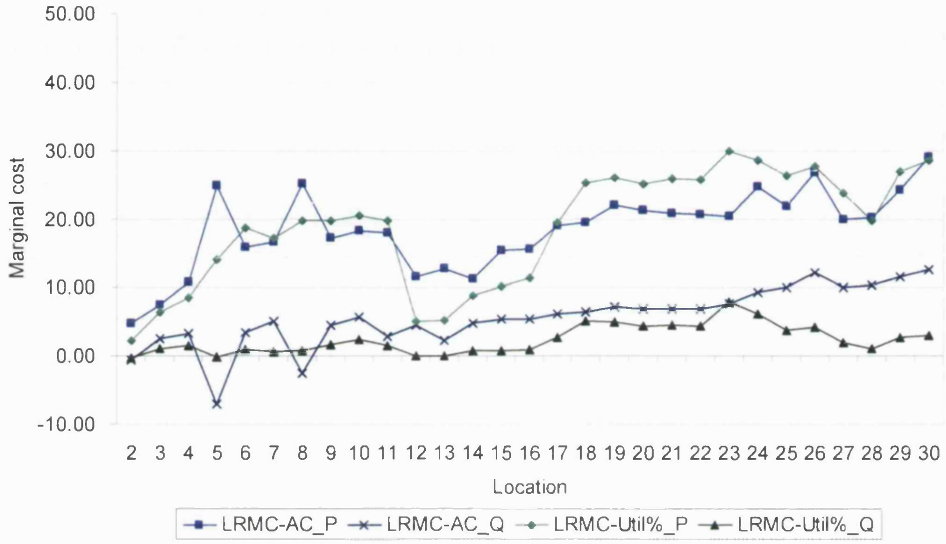


Figure 6.33: LRMC-AC and LRMC-Util% price comparison on reinforcement IEEE-30 bus test system

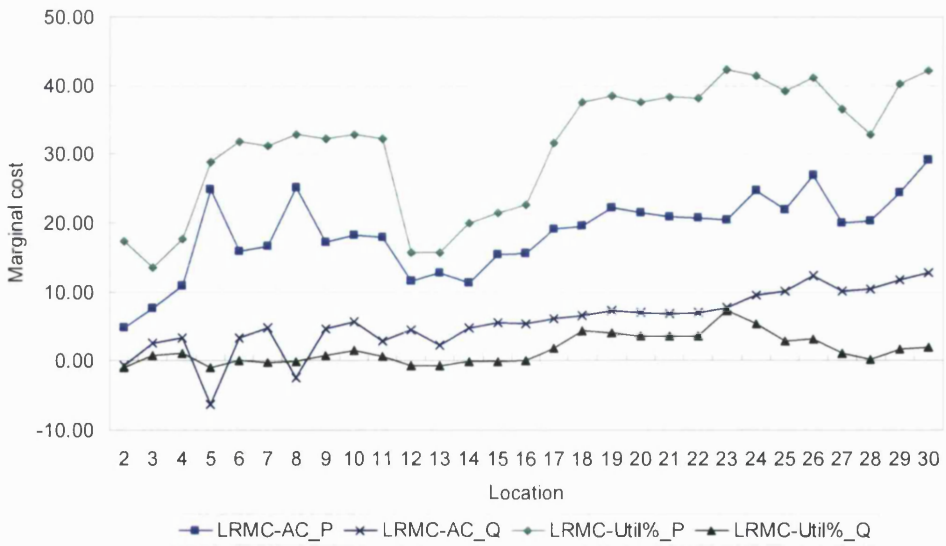


Figure 6.34: LRMC-AC and LRMC-Util% price comparison on original IEEE-30 bus test system

Compared with the original case in Figure 6.34, the change of nodal prices using LRMC-Util% is much higher than that using LRMC-AC. Because the reinforced line is connected to the slack bus, the nodal prices of all nodes reduce due to the releasing of the highly utilized capacity of the network.

Therefore, the LRMC-Util% pricing methodology indicates that better investment can bring greater benefits to network users. This can provide an incentive for proper investment in new network infrastructure. LRMC-AC pricing methodology can not offer such a price signal for network investment.

6.5 Chapter summary

Compared with the proposed LRMC-DC and LRMC-AC model in Chapter 5, the LRMC-Util% pricing methodology can truly reflect the network long-run costs, and ensure that the costs are properly taken into account in the overall costs incurred in the choice of site. As shown in Figure 6.35, the final cost at a node is set in the marginal cost ranging between MC_{base} and MC_{future}, which is a competitive price following the discontinuous marginal cost curve, as described in Chapter 2 Section 2.2.3. If a node sits at a highly utilized part of the network, the present value of future investment will be higher. So the marginal cost will be closer to the MC_{future}. Moreover, the proposed LRMC-Util% methodology distinguishes successfully the costs at different locations, recognizes the reactive power, and provides the economic signals for network users to locate new loads and generation.

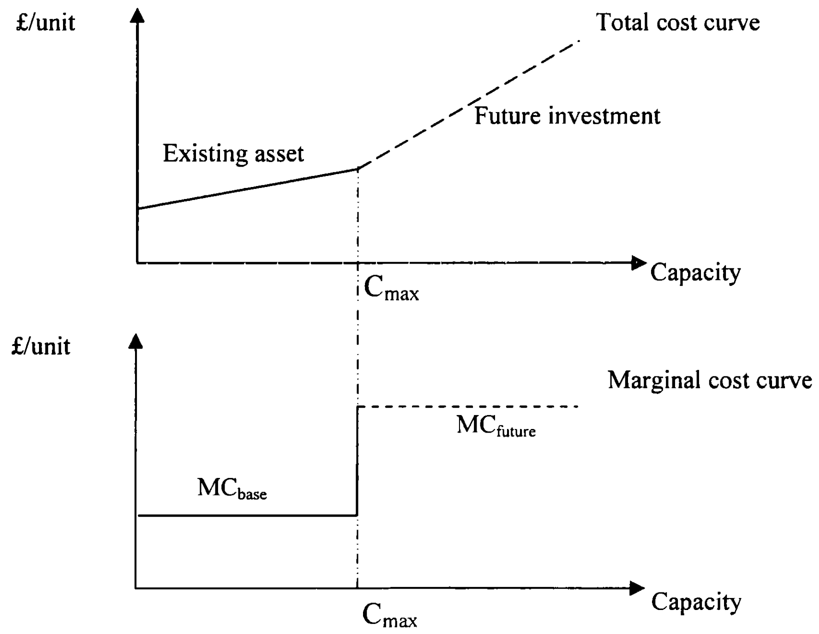


Figure 6.35: Discontinuous future investment MC curve

Chapter 7

Conclusions and Future Work

Conclusions are drawn from discussions in the previous chapters and the findings from the case studies presented. Finally, a number of works outside the scope of this thesis, but nevertheless considered to be important extensions to the work presented in this thesis, are mentioned. These would enable the developed methodologies to be transformed into suitable forms for adoption in real world network charging methodologies.

7.1 Conclusions

Countries all over the world have committed to or currently in the process of introducing more competition into their power industries. Moving from monopolies to competitive electricity markets, open access to transmission and distribution networks is the vehicle used to promote effective competition in the electricity supply industry. Therefore, the use of network prices set by network companies play a more and more crucial role in providing economic efficient signals for siting and sizing of oncoming generators and demands, and incentivizing the efficient use of networks.

In the U.K., the increasing penetration of embedded generators (EGs) in current and future electricity distribution networks leads to the changing in transmission network development. This would question the appropriateness of the existing transmission pricing arrangement, which does not have the scope to deal with EGs [Pos 2001]. At the same time, because the current distribution pricing method using distribution reinforcement model (DRM) is based on postage stamp pricing method, essentially, has the same use of system charge regardless of the locations at each voltage level [Tur 2005, Wpd 2006a]. Without economic efficient price signals, EGs could potentially locate at areas which cause great network investment. This research is therefore proposing and exploring alternative efficient network pricing methodologies to incentivize appropriate sitting of EGs and demands.

The DCLF Investment Cost Related Pricing (ICRP) model adopted by the National Grid Company (NGC), UK, is a practical example of long-run marginal cost with DC load flow (LRMC-DC) [Ngc 2006b]. It can reflect the asset costs, and provide the locational signals for both generators and demands. It is one of advanced pricing methodologies so far. In this thesis, LRMC-DC pricing method was extended to a practical distribution network in the first time, to test its suitability in distribution networks. The results indicate that it is capable of generating locational nodal prices on distribution networks, reflecting the distance power travelled from points of generators to points of consumers, overcoming the shortage of the current DRM pricing, which has the average price at the same voltage level.

However, LRMC-DC based methodologies are not capable of pricing reactive power, yet reactive power is very important in network investment and operation. New reactive power price allocation methodologies are proposed and demonstrated as the *perpendicular approach* and the *arc approach*. They are named from the different lines made in the triangle relationship between apparent power and real/reactive power to define the reactive power cost. The *perpendicular approach* decides the unit cost of real and reactive power according to the power factor [Li 2005a, Li 2006]. The *arc approach* keeps the same real power price as LRMC-DC and allocates the price difference between the apparent power and the real power to the reactive power, which is more straightforward to explain the reactive power price to network users.

In the development of the two novel methodologies above, the existing LRMC-DC method was modified into the LRMC-AC method to reflect the effects of reactive power on network performance and capacity requirement. LRMC-AC will produce high reactive power prices for customers with poor power factors, and low reactive power prices for customers with good power factors. For the network users, the allocation of reactive power cost encourages the consumers to operate at a better power factor as they attempt to minimise their network charges. However, the reactive power price would have to be sufficiently high to make a business case in investing in power factor correction equipment or changing operating regimes to minimise reactive power charges. This applies equally to demand and generation network users. For the network owner, the prices covered by reactive power can also bring locational signals to install local reactive power compensation devices.

The advantage in cost reflectivity of the LRMC-AC pricing methodology over LRMC-DC demonstrated on the IEEE-30 bus test system and the practical 110 bus distribution test system. On both test systems, LRMC-AC can cover around 5% more of the capital cost than LRMC-DC due to the reactive power price. Compared with the highest real power price £22 KW/Yr, the highest reactive power price is £12 KVAr/Yr on the IEEE-30 bus test system, and £9 KVAr/Yr on the distribution test system, which the reactive power price is sufficiently high to influence the customers to correct their power factors.

Because LRMC-AC only gears for reflecting the distances and paths to support nodal customers, it however does not reflect the degree of utilisation, the LRMC-AC prcing methodology was further improved into the LRMC-Util% pricing methodology, capable of dealing with network utilisation. As one of the major contribution in this research, LRMC-Util% is a new proposed pricing methodology. In this method, the headroom of network asset is related with future reinforcement cost. That is, if the reinforcement incurred earlier, the present value of the future investment will be higher; otherwise, if the reinforcement happened later, the present value will be lower.

Compared to LRMC-AC, the LRMC-Util% encourages more efficient use of the existing network. It incentivizes generation connection in areas with highly loaded circuits, and incentivizes demand connections in areas with lightly loaded circuits. LRMC-Util% can therefore provide a proper price signal for siting embedded generation hence releasing the capacity of highly utilized areas of the network. Consequently, the network prices can be reduced with decreased network utilisation. Additionally, LRMC-Util% reflects both increases in the nodal prices with demand growth and reduction in the nodal prices with network reinforcements. Without consideration of utilisation, using LRMC-AC, network prices hardly change due to only distances and power travel paths being considered.

Overall, LRMC-Util% is aimed at allocating network asset costs based on the usage of the network facilities from study nodes. It involves evaluating the future network investment requirements and fairly allocating the future network costs to users. The advantages of LRMC-Util% include the ability to reflect the forward looking costs, to distinguish the costs at different locations, to recognize the reactive power, and to derive charges for both generation and demand users.

Thus, the benefits derived from LRMC-Util% methodology appeal to network owners, network generation and demand users alike. For network owners, it can reduce the future investment costs and release the network capacity. For generation and demands, it can produce the lower use of network charges. Ultimately, the end consumers will benefit from reduced electricity prices.

7.2 Future Work

A number of areas, outside the scope of this thesis, that require further research and evaluation were identified. The issues briefly described here were considered to be important extensions to the work presented in this thesis to enable the developed methodologies to be useable in real world network charging methodologies.

1. Network benefits analysis

The embedded generator response and demand increase case studies of Chapter 7 do not consider the network physical limitations. If a generator connected to the network, the network facilities may not have sufficient capacity to adequately deal with possible increases in power flows. On the other hand the generator could 'free up' network capacity if it is largely supplying local load. Network benefit analysis is to determine whether there are potential benefits that could arise from using different pricing regimes, and thus help inform the consideration of any new network pricing framework. The study carried out by the University of Bath [Li 2005b], in which the author was involved, is a good example, which indicates that the Bath University Model, related to the LRMC-Util% pricing method, can bring more benefits by deferring network investment when compared with other pricing models.

2. Different time of use of network

In LRMC pricing methodologies, demand profile is one of the most important input system data. The simultaneous maximum demand of the system is taken as the demands data. In the existing network pricing regimes, such as ICRP, DRM, there are a few ways to define the system maximum demand. But realistically certain customers reach their maximum load condition during the system off-peak time. It is possible to calculate another set of LRMC price based on off-peak time. The question is how to split the system asset cost amongst the different time periods, and how to allocate the cost to the customers who have their maximum load condition at the system off-peak time.

3. Various characteristic of different distribution network

The distribution test network is a practical network based on the distribution system in the South Wales. The configuration of network in other distribution zones can be very different from the distribution test network here. For example, the distribution network in Central London is fully built by underground cable. The asset cost will be much higher than other areas and the characteristics will be very different from the test network. LRMC-Uitl% should be tested on a diverse range of practical distribution networks to verify its robustness.

In the end, it is hoped that this thesis will stimulate further research in the network pricing area.

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A Derivation of NGC TNUoS Tariff

A-1 Calculation of Zonal Generation Tariff [Ngc 2006b]

Let us consider all nodes in generation zone 4:Western Highland.

The table below shows a sample output of the transport model comprising the node, the marginal km of an injection at the node with a consequent withdrawal at the reference node, the generation sited at the node, scaled to ensure total national generation equals total national demand.

No.	Gen Zone	Node Name	Nodal Marginal km	Scaled Gen (MW)	Gen Weighted Nodal Marginal km
1	4	LAGG1Q	1113.41	0.00	
2	4	CEAN1Q	1133.18	54.41	366.48
3	4	FASN10	1143.82	38.50	261.75
4	4	FAUG10	1100.10	0.00	
5	4	FWIL1Q	1009.79	0.00	
6	4	FWIL1R	1009.79	0.00	
7	4	GLEN1Q	1123.82	43.52	290.71
8	4	INGA1Q	1087.40	16.74	108.20
9	4	MILL1Q	1101.55	0.00	
10	4	MILL1S	1106.76	0.00	
11	4	QUOI10	1123.82	15.07	100.67
12	4	QUOI1Q	1120.49	0.00	
13	4	LOCL1Q	1082.41	0.00	
14	4	LOCL1R	1082.41	0.00	
			Totals	168.24	1127.81

In order to calculate the generation tariff we would carry out the following steps:

1. Calculate the generation weighted nodal shadow cost.

$$\text{Gen Weighted Nodal Marginal km} = \frac{NodalM\arg inalKm \cdot ScaledGeneration}{TotalScaledGeneraion}$$

2. Sum the generation weighted nodal shadow cost to give a zonal figure.

For zone 4 this would be:

(366.48 + 261.75 + 290.71 + 108.20 + 100.67) km = 1127.81 km

3. Modify the zonal figure in Step 2 above by the generation/demand split correction factor. This ensures that the 27:73 (approx) split of revenue recovery between generation and demand is retained.

For zone 4 this would be say: 1127.81 km + (-239.60 km) = 888.21 km

-239.60 km is the generation/demand split correction factor. It is calculated by simultaneous equation to give the correct split of total revenue.

4. Calculate the transport tariff by multiplying the figure in Step 3 above by the expansion constant (& dividing by 1000 to put into units of £/kW).

For zone 4 and assuming an expansion constant of £9.80/MWkm and a locational security factor of 1.8:

(888.21 km * £9.80/MWkm * 1.8) / 1000 = £15.67 / kW

5. Calculate the residual tariff.

Assuming the total revenue to be recovered from TNUoS is £1067m, the total recovery from generation would be (27% * £1067m) = £288m.

Assuming the total recovery from generation transport tariffs is £70m and total forecast chargeable generation capacity is 67000MW

The Generation residual tariff would be as follows:

(£288m-£70m)/65000MW =£3.35 / KW

6. To get to the final tariff, add the generation residual tariff to zonal generation transport tariff.

For zone 4: £15.67/kW + £3.35/kW = £19.02 / kW

To summarise, in order to calculate the generation tariffs, it needs evaluate a generation weighted zonal marginal km cost, modify by a re-referencing quantity to ensure that our revenue recovery split between generation and demand is correct, multiply by the security factor, then add a constant (termed the residual cost) to give the overall tariff.

A-2 Calculation of Zonal Demand Tariff [Ngc 2006b]

Let us consider all nodes in demand zone 14: South Western.

The table below shows a sample output of the transport model comprising the node, the marginal km of an injection at the node with a consequent withdrawal at the reference node, the generation sited at the node, scaled to ensure total national generation = total national demand and the demand sited at the node.

No	Dem Zone	Node	Nodal Marginal km	Dem (MW)	Demand Weighted Nodal Marginal km
1	14	ABHA4B	-381.25	148.5	-18.39
2	14	ABHA4A	-381.72	148.5	-18.42
3	14	ALVE4A	-328.31	113	-12.05
4	14	ALVE4B	-328.31	113	-12.05
5	14	AXMI40_SWEB	-337.53	117	-12.83
6	14	BRWA2A	-281.64	92.5	-8.46
7	14	BRWA2B	-281.72	92.5	-8.47
8	14	EXET40	-320.12	357	-37.13
9	14	HINP20	-247.67	4	-0.32
10	14	HINP40	-247.67	0	
11	14	INDQ40	-401.28	450	-58.67
12	14	IROA20_SWEB	-194.88	594	-37.61
13	14	LAND40	-438.65	297	-42.33
14	14	MELK40_SWEB	-162.96	102	-5.40
15	14	SEAB40	-63.21	352	-7.23
16	14	TAUN4A	-273.79	0	
17	14	TAUN4B	-273.79	97	-8.63
			Totals	3078	287.99

In order to calculate the demand tariff we would carry out the following steps:

1. Calculate the demand weighted nodal shadow costs.

$$\text{Demand Weighted Nodal Marginal km} = \frac{NodalM\arg inalKm \cdot Demand}{TotalDemand}$$

2. Sum the demand weighted nodal shadow cost to give a zonal figure.

For zone 14 this is shown in the above table and is 287.99km.

3. Modify the zonal figure in Step 2 above by the generation/demand split correction factor.

For zone 14 this would be say: 287.99km - (-239.60km) = 527.59 km

-239.60 km is the generation/demand split correction factor. It is calculated by simultaneous equation to give the correct split of total revenue.

4. Calculate the transport tariff by multiplying the figure in Step 3 above by the expansion constant (& dividing by 1000 to put into units of £/kW).

For zone 14, assuming an expansion constant of £9.80/MWkm and a locational security factor of 1.80:

(527.59km * £9.80/MWkm * 1.8) / 1000= £9.31/kW

5. Calculate the residual tariff.

Assuming the total revenue to be recovered from TNUoS is £1067m, the total recovery from generation would be (73% * £1067m) = £779m.

Assuming the total recovery from generation transport tariffs is £130m and total forecast chargeable generation capacity is 50000MW

The demand residual tariff would be as follows:

(£779m-£130m)/50000MW = £12.98/KW

6. To get to the final tariff, add the demand residual tariff to demand zonal transport tariff.

For zone 14: £9.31 / kW + £12.98 / kW = £22.29 / kW

7. The final demand tariff is subject to further adjustment to allow for the minimum £0/kw demand charge and the small generators recovery.

A-3 NGC Official TNUoS Tariffs

2004/05 Final Tariffs:

Demand

Zone No.	Zone Name.	HH Zonal Tariff (£/kW)	NHH Zonal Tariff (p/kWh)
1	Northern	4.940866	0.656585
2	North West	8.325173	1.100254
3	Yorkshire	8.455923	1.171611
4	N Wales & Mersey	8.709914	1.107068
5	East Midlands	10.771600	1.479424
6	Midlands	12.600874	1.733413
7	Eastern	11.007104	1.394934
8	South Wales	16.130442	2.228075
9	South East	14.321101	1.773924
10	London	16.761568	2.430277
11	Southern	15.679987	2.076489
12	South Western	17.798154	2.198679

Generation

Zone No.	Zone Name	Zonal Tariff (£/kW)
1	Northern	9.009237
2	Humberside	5.767201
3	North West	6.222266
4	Pennines & North Wales	4.121912
5	Dinorwig	10.715347
6	Anglesey	7.011370
7	East Anglia	2.889748
8	West Midlands	2.032089
9	South Wales & Gloucs	-2.150590
10	Oxon & Bucks	0.004330
11	Estuary	1.733641
12	Central & SW London	-6.604821
13	South Coast	-1.507146
14	Wessex	-3.829097
15	Peninsula	-6.836065

2005/06 Final Tariffs:

Demand

Zone No.	Zone Name.	HH Zonal Tariff (£/kW)	NHH Zonal Tariff (p/kWh)
1	Northern Scotland	0.041110	0.005610
2	Southern Scotland	4.114438	0.561693
3	Northern	7.393664	0.970234
4	North West	11.137060	1.461966
5	Yorkshire	11.182059	1.487585
6	N Wales & Mersey	11.210216	1.512416
7	East Midlands	13.465848	1.804975
8	Midlands	15.026957	2.062601
9	Eastern	14.028455	1.909865
10	South Wales	18.315906	2.368863
11	South East	15.989410	2.167559
12	London	18.516693	2.454909
13	Southern	17.833397	2.446575
14	South Western	20.489868	2.728435

Residual Charge for Demand (£/kW) 11.190000

Generation

Zone No.	Zone Name	Zonal Tariff (£/kW)
1	Peterhead	18.162236
2	North Scotland	20.929759
3	Skye	23.095483
4	Western Highland	18.920247
5	Central Highlands	15.360647
6	Cruachan	15.852828
7	Argyll	13.441972
8	Stirlingshire	12.610665
9	South Scotland	11.820471
10	North East England	8.090616
11	Humber, Lancashire & SW Scotland	4.906290
12	Anglesey	6.122706
13	Dinorwig	8.705520
14	South Yorks & North Wales	3.120190
15	Midlands & South East	1.322966
16	Central London	-5.712196
17	North London	-0.220327
18	Oxon & South Coast	-0.698936
19	South Wales & Gloucester	-2.552479
20	Wessex	-4.951295
21	Peninsula	-8.044943

Residual Charge for Generation **(£/kW)** 3.257

B Test System Data

B-1 IEEE 30 Bus Test System

Figure B.1 is shown the standard IEEE-30 bus test system. The bus data, line data, and transformer data are given in Table B.1, B.2, and B.3, respectively. And the base MVA is 100 [Pow 2006].

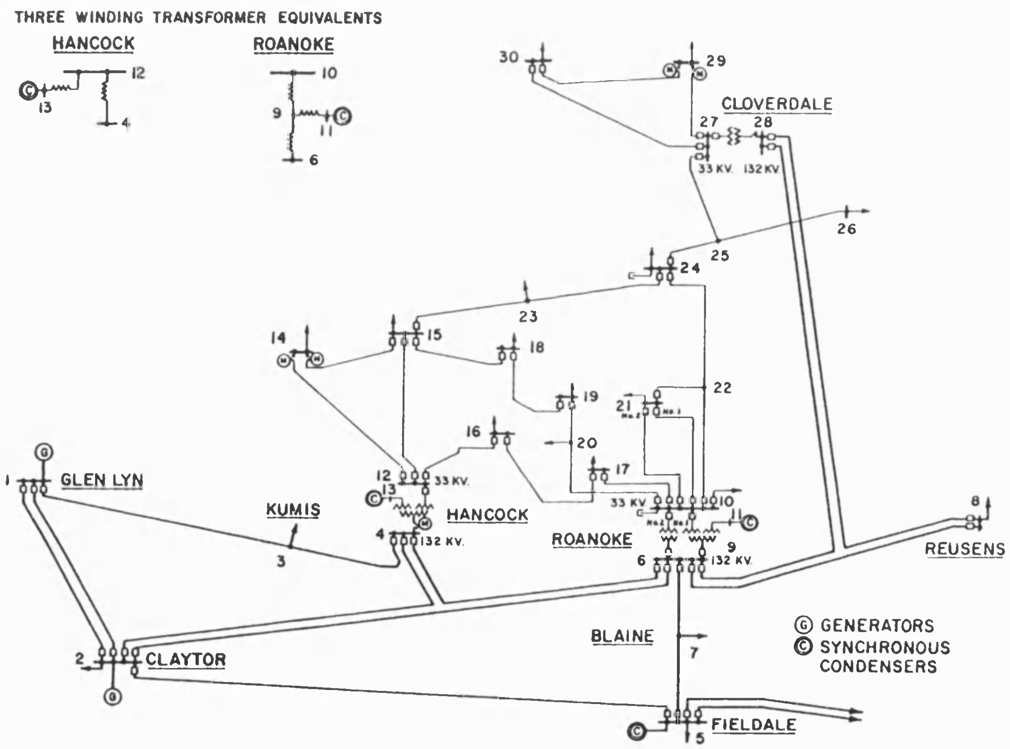

Figure B.1: IEEE 30-bus test system

Table B.1: Bus data

Bus No.	Bus Name	Base KV	Type	Demand		Generator/Condenser	
				P(MW)	Q(MVar)	P(MW)	Q(MVar)
1	Bus 1	132	Slack	-	-	-	-
2	Bus 2	132	Generator	21.7	0.0	40.0	50.0
3	Bus 3	132	Load	2.4	1.2	-	-
4	Bus 4	132	Load	7.6	1.6	-	-
5	Bus 5	132	Condenser	94.2	0.0	0.0	37.0
6	Bus 6	132	Load	-	-	-	-
7	Bus 7	132	Load	22.8	10.9	-	-
8	Bus 8	132	Condenser	30.0	0.0	0.0	37.3
9	Bus 9	1.0	Load	-	-	-	-
10	Bus 10	33	Load	5.8	2.0	-	-
11	Bus 11	11	Condenser	-	-	0.0	16.2
12	Bus 12	33	Load	11.2	7.5	-	-
13	Bus 13	11	Condenser	-	-	0.0	10.6
14	Bus 14	33	Load	6.2	1.6	-	-
15	Bus 15	33	Load	8.2	2.5	-	-
16	Bus 16	33	Load	3.5	1.8	-	-
17	Bus 17	33	Load	9.0	5.8	-	-
18	Bus 18	33	Load	3.2	0.9	-	-
19	Bus 19	33	Load	9.5	3.4	-	-
20	Bus 20	33	Load	2.2	0.7	-	-
21	Bus 21	33	Load	17.5	11.2	-	-
22	Bus 22	33	Load	-	-	-	-
23	Bus 23	33	Load	3.2	1.6	-	-
24	Bus 24	33	Load	8.7	6.7	-	-
25	Bus 25	33	Load	-	-	-	-
26	Bus 26	33	Load	3.5	2.3	-	-
27	Bus 27	33	Load	-	-	-	-
28	Bus 28	33	Load	-	-	-	-
29	Bus 29	33	Load	2.4	0.9	-	-
30	Bus 30	33	Load	10.6	1.9	-	-

Table B.2: Line data

From	To	Base KV	Resistance R	Reactance X	Susceptance Ch	Overhead line cost (£)	Underground cable cost (£)	Rating (MVA)
1	2	132	0.0192	0.0575	0.0528	11,505,736	1,375,000	400
1	3	132	0.0452	0.1652	0.0408	11,505,736	825,000	300
2	4	132	0.057	0.1737	0.0368	17,258,604	550,000	200
3	4	132	0.0132	0.0379	0.0084	5,752,868	0	300
2	5	132	0.0472	0.1983	0.0418	20,135,038	825,000	400
2	6	132	0.0581	0.1763	0.0374	17,258,604	550,000	200
4	6	132	0.0119	0.0414	0.009	8,629,302	0	200
5	7	132	0.046	0.116	0.0204	17,258,604	550,000	200
6	7	132	0.0267	0.082	0.017	5,752,868	275,000	200

6	8	132	0.012	0.042	0.009	8,629,302	0	200
12	14	33	0.1231	0.2559	0	577,318	164,080	32
12	15	33	0.0662	0.1304	0	288,659	164,080	32
12	16	33	0.0945	0.1987	0	346,391	164,080	32
14	15	33	0.221	0.1997	0	721,648	0	16
16	17	33	0.0524	0.1923	0	230,927	0	16
15	18	33	0.1073	0.2185	0	432,989	0	16
18	19	33	0.0639	0.1292	0	288,659	0	16
19	20	33	0.034	0.068	0	115,464	0	32
10	20	33	0.0936	0.209	0	346,391	164,080	32
10	17	33	0.0324	0.0845	0	115,464	164,080	32
10	21	33	0.0348	0.0749	0	144,330	164,080	30
10	22	33	0.0727	0.1499	0	288,659	164,080	30
21	22	33	0.0116	0.0236	0	57,732	0	30
15	23	33	0.1	0.202	0	432,989	164,080	16
22	24	33	0.115	0.179	0	432,989	0	30
23	24	33	0.132	0.27	0	577,318	0	16
24	25	33	0.1885	0.3292	0	721,648	0	30
25	26	33	0.2544	0.38	0	865,977	0	30
25	27	33	0.1093	0.2087	0	432,989	0	30
27	29	33	0.2198	0.4153	0	721,648	164,080	30
27	30	33	0.3202	0.6027	0	1,154,636	164,080	30
29	30	33	0.2399	0.4533	0	865,977	164,080	30
8	28	132	0.0636	0.2	0.0428	23,011,472	1,100,000	200
6	28	132	0.0169	0.0599	0.013	11,505,736	0	200

Table B.3: Transformer data

From	Base KV	To	Base KV	Resistance R	Reactance X	Susceptance Ch	Related cost (£)	Rating (MVA)
6	132	9	1	0	0.208	0	568,402	100
6	132	10	33	0	0.556	0	568,402	100
11	11	9	1	0	0.208	0	490,695	100
10	33	9	1	0	0.11	0	490,695	100
4	132	12	33	0	0.256	0	568,402	100
12	33	13	11	0	0.14	0	490,695	65
28	132	27	33	0	0.396	0	1,136,805	100

The power flow result of IEEE-30 bus test system is following:

Bus Data

Bus	V(pu)	V(kV)	V(theta)	Pg(MW)	Qg(MVAr)	Pd(MW)	Qd(MVAr)	LoadPf
1	1.06	139.92	0.00	261.71	13.25	0	0	----
2	1.03	136.29	-5.24	0	0	-18.3	-37.3	-0.44
3	1.00	132.39	-7.38	0	0	2.4	1.2	0.89
4	0.99	130.65	-9.12	0	0	7.6	1.6	0.98
5	0.99	130.87	-14.26	0	0	94.2	-18	0.98

6	0.99	129.98	-10.91	0	0	0	0	----
7	0.98	129.28	-12.84	0	0	22.8	10.9	0.90
8	0.98	129.91	-11.70	0	0	30	-7.3	0.97
9	1.00	1.00	-14.09	0	0	0	0	----
10	0.99	32.55	-15.80	0	0	5.8	2	0.95
11	1.04	11.40	-14.09	0	0	0	-16.2	----
12	1.01	33.47	-15.25	0	0	11.2	7.5	0.83
13	1.03	11.31	-15.25	0	0	0	-10.6	----
14	1.00	32.88	-16.20	0	0	6.2	1.6	0.97
15	0.99	32.66	-16.23	0	0	8.2	2.5	0.96
16	0.99	32.82	-15.74	0	0	3.5	1.8	0.89
17	0.98	32.46	-16.04	0	0	9	5.8	0.84
18	0.98	32.20	-16.85	0	0	3.2	0.9	0.96
19	0.97	32.04	-17.01	0	0	9.5	3.4	0.94
20	0.97	32.14	-16.77	0	0	2.2	0.7	0.95
21	0.97	32.13	-16.29	0	0	17.5	11.2	0.84
22	0.97	32.15	-16.26	0	0	0	0	----
23	0.98	32.16	-16.56	0	0	3.2	1.6	0.89
24	0.96	31.78	-16.61	0	0	8.7	6.7	0.79
25	0.97	31.99	-16.32	0	0	0	0	----
26	0.95	31.38	-16.79	0	0	3.5	2.3	0.84
27	0.98	32.42	-15.85	0	0	0	0	----
28	0.98	129.28	-11.56	0	0	0	0	----
29	0.96	31.73	-17.19	0	0	2.4	0.9	0.94
30	0.95	31.33	-18.15	0	0	10.6	1.9	0.98

Line Data

FromBus	ToBus	V(kV)	Pij(MW)	Qij(MVAr)	Pji(MW)	Qji(MVAr)	PLoss(MW)	Util%
1	2	132	174.09	-2.45	-168.91	12.18	5.18	42.90
1	3	132	87.62	15.70	-84.40	-8.28	3.22	29.00
2	4	132	43.85	10.41	-42.74	-10.79	1.11	22.30
3	4	132	82.00	7.08	-81.11	-5.36	0.89	27.30
2	5	132	82.85	5.83	-79.78	2.78	3.07	20.40
2	6	132	60.51	8.88	-58.45	-6.44	2.06	30.00
4	6	132	71.33	-7.71	-70.70	9.01	0.62	35.80
5	7	132	-14.42	15.22	14.64	-16.65	0.22	10.80
6	7	132	37.84	-6.15	-37.44	5.75	0.40	19.10
6	8	132	29.74	-7.40	-29.62	6.93	0.12	15.30
12	14	33	8.08	3.16	-7.99	-2.97	0.09	26.90
12	15	33	18.20	9.82	-17.92	-9.28	0.28	63.80
12	16	33	7.45	6.53	-7.36	-6.34	0.09	30.60
14	15	33	1.79	1.37	-1.78	-1.36	0.01	14.00
16	17	33	3.86	4.54	-3.84	-4.47	0.02	37.00
15	18	33	6.36	3.23	-6.31	-3.12	0.06	44.30
18	19	33	3.11	2.22	-3.10	-2.20	0.01	23.80
19	20	33	-6.40	-1.20	6.42	1.23	0.02	20.40
10	20	33	8.70	2.11	-8.62	-1.93	0.08	27.80
10	17	33	5.17	1.36	-5.16	-1.33	0.01	16.70
10	21	33	15.35	9.89	-15.23	-9.63	0.12	60.50

10	22	33	7.33	4.52	-7.28	-4.41	0.06	28.50
21	22	33	-2.27	-1.57	2.27	1.57	0.00	9.20
15	23	33	5.14	4.91	-5.09	-4.80	0.05	44.10
22	24	33	5.01	2.84	-4.97	-2.78	0.04	19.10
23	24	33	1.89	3.20	-1.87	-3.17	0.02	23.10
24	25	33	-1.86	-0.76	1.87	0.77	0.01	6.70
25	26	33	3.55	2.37	-3.50	-2.30	0.05	14.10
25	27	33	-5.42	-3.15	5.47	3.23	0.05	21.00
27	29	33	6.20	1.69	-6.11	-1.51	0.09	21.20
27	30	33	7.11	1.69	-6.93	-1.36	0.18	23.90
29	30	33	3.71	0.61	-3.67	-0.54	0.04	12.40
8	28	132	-0.38	0.37	0.38	-4.49	0.00	1.30
6	28	132	19.23	2.74	-19.16	-3.75	0.07	9.70

Transformer Data

FromBus	ToBus	Pij(MW)	Qij(MVAr)	Pji(MW)	Qji(MVAr)	PLoss(MW)	Util%	TapRatio
6	9	26.96	2.15	-26.96	-0.65	0	27.00	0.98
6	10	15.39	6.09	-15.39	-4.62	0	16.30	0.97
11	9	0.00	16.20	0.00	-15.69	0	15.90	1.00
10	9	-26.96	-15.26	26.96	16.34	0	31.30	1.00
4	12	44.92	22.26	-44.92	-16.55	0	49.00	0.93
12	13	0.00	-10.45	0.00	10.60	0	16.20	1.00
28	27	18.78	8.24	-18.78	-6.61	0	20.20	0.97

B-2 Distribution Test System

Figure B.2 is shown the distribution test system in the South Wales area of England.

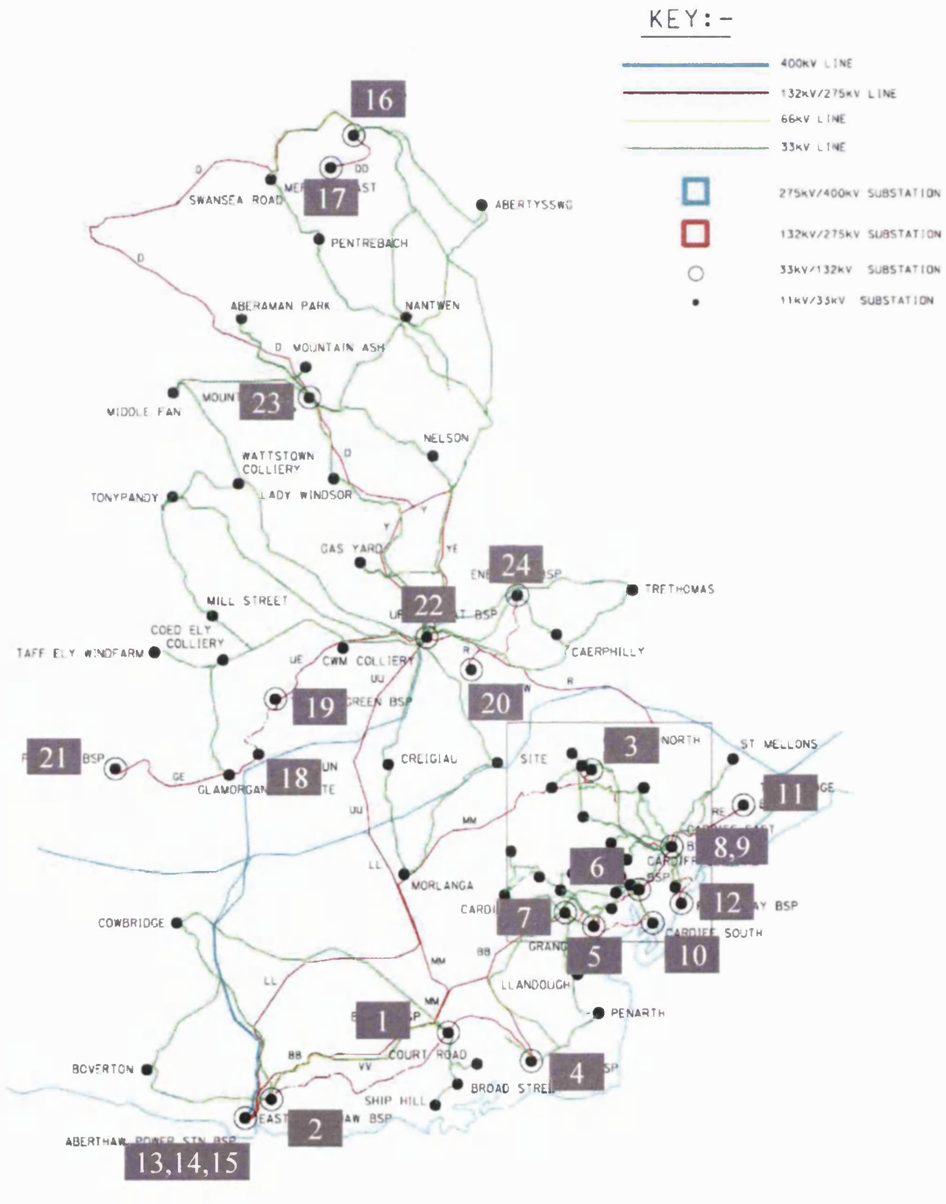

Figure B.2: Geographic map of distribution test system

The bus data, line data, and transformer data are given in Table B.4, B.5, and B.6, respectively. And the base MVA is 100.

Table B.4: Bus data

Bus No.	Bus Name	Base KV	Type	Demand		Generator/Condenser	
				P(MW)	Q(MVar)	P(MW)	Q(MVar)
5001	Bus 5001	275	-	-	-	-	-
5043	Bus 5043	275		-	-	-	-
5080	Bus 5080	275	Slack	-	-	-	-
5081	Bus 5081	275		-	-	-	-
5242	Bus 5242	275		-	-	-	-
2270	Bus 2270	132		-	-	-	-
2271	Bus 2271	132		-	-	-	-
1	Bus 1	33	Load	34.77	3.47	-	-
2280	Bus 2280	132		-	-	-	-
2281	Bus 2281	132		-	-	-	-
2	Bus 2	33	Load	24.59	17.42	-	-
2290	Bus 2290	132		-	-	-	-
3	Bus 3	33	Load	40.11	6.61	-	-
2300	Bus 2300	132		-	-	-	-
2301	Bus 2301	132		-	-	-	-
2302	Bus 2302	132		-	-	-	-
4	Bus 4	11	Load	20.70	8.20	-	-
2310	Bus 2310	132		-	-	-	-
5	Bus 5	11	Load	21.00	6.10	-	-
2320	Bus 2320	132		-	-	-	-
6	Bus 6	33	Load	32.55	3.01		
2330	Bus 2330	132		-	-	-	-
7	Bus 7	33	Load	81.18	27.07	-	-
8	Bus 8	33	Load	102.63	36.33	-	-
9	Bus 9	11	Load	29.80	8.70	-	-
2350	Bus 2350	132		-	-	-	-
10	Bus 10	11	Load	30.50	10.00	-	-
2360	Bus 2360	132		-	-	-	-
2361	Bus 2361	132		-	-	-	-
11	Bus 11	11	Load	7.40	1.50	-	-
2660	Bus 2660	132		-	-	-	-
12	Bus 12	11	Load	7.80	1.60	-	-
2724	Bus 2724	11		-	-	-	-
2725	Bus 2725	11		-	-	-	-
2726	Bus 2726	11		-	-	-	-
2727	Bus 2727	11		-	-	-	-
2730	Bus 2730	132		-	-	-	-
2731	Bus 2731	132		-	-	-	-
2735	Bus 2735	11		-	-	-	-
13	Bus 13	11	Generator	-	-	32.30	10.61
14	Bus 14	11	Generator	-	-	171.00	56.20
15	Bus 15	11	Generator	-	-	57.00	18.73

2739	Bus 2739	6.6		-	-	-	-
2740	Bus 2740	132		-	-	-	-
2741	Bus 2741	132		-	-	-	-
2742	Bus 2742	132		-	-	-	-
2745	Bus 2745	11		-	-	-	-
2746	Bus 2746	11		-	-	-	-
2747	Bus 2747	11		-	-	-	-
2748	Bus 2748	11		-	-	-	-
2749	Bus 2749	6.6		-	-	-	-
2750	Bus 2750	132		-	-	-	-
2751	Bus 2751	132		-	-	-	-
2755	Bus 2755	11		-	-	-	-
2756	Bus 2756	11		-	-	-	-
2757	Bus 2757	11		-	-	-	-
2812	Bus 2812	11		-	-	-	-
3834	Bus 3834	132		-	-	-	-
5000	Bus 5000	275		-	-	-	-
5008	Bus 5008	132		-	-	-	-
5009	Bus 5009	132		-	-	-	-
5010	Bus 5010	132		-	-	-	-
5011	Bus 5011	132		-	-	-	-
5040	Bus 5040	275		-	-	-	-
5050	Bus 5050	132		-	-	-	-
5051	Bus 5051	132		-	-	-	-
5052	Bus 5052	132		-	-	-	-
2092	Bus 2092	132		-	-	-	-
2093	Bus 2093	132		-	-	-	-
2370	Bus 2370	132		-	-	-	-
2371	Bus 2371	132		-	-	-	-
16	Bus 16	33	Load	32.35	12.07	-	-
2381	Bus 2381	132		-	-	-	-
2382	Bus 2382	132		-	-	-	-
2390	Bus 2390	132		-	-	-	-
2391	Bus 2391	132		-	-	-	-
17	Bus 17	11	Load	26.10	6.50	-	-
2400	Bus 2400	132		-	-	-	-
2401	Bus 2401	132		-	-	-	-
18	Bus 18	11	Load	15.30	6.00		
2403	Bus 2403	132		-	-	-	-
2404	Bus 2404	132		-	-	-	-
19	Bus 19	11	Load	24.00	9.50	-	-
2406	Bus 2406	11		-	-	-	-
2410	Bus 2410	132		-	-	-	-
2411	Bus 2411	132		-	-	-	-
20	Bus 20	11	Load	16.00	5.30	-	-
2416	Bus 2416	132		-	-	-	-
2418	Bus 2418	132		-	-	-	-
2419	Bus 2419	132		-	-	-	-
2420	Bus 2420	132		-	-	-	-
2421	Bus 2421	132		-	-	-	-
21	Bus 21	11	Load	16.70	6.60	-	-

22	Bus 22	11	Load	23.00	0.00	-	-
2800	Bus 2800	132		-	-	-	-
2801	Bus 2801	132		-	-	-	-
2802	Bus 2802	132		-	-	-	-
2803	Bus 2803	132		-	-	-	-
2804	Bus 2804	132		-	-	-	-
2805	Bus 2805	132		-	-	-	-
2808	Bus 2808	132		-	-	-	-
2809	Bus 2809	132		-	-	-	-
23	Bus 23	33	Load	11.67	13.88	-	-
24	Bus 24	11	Load	11.50	4.60	-	-
4446	Bus 4446	11		-	-	-	-
4449	Bus 4449	11		-	-	-	-
5240	Bus 5240	275		-	-	-	-
5250	Bus 5250	132		-	-	-	-
5251	Bus 5251	132		-	-	-	-
5252	Bus 5252	132		-	-	-	-

Table B.5: Line data

From	To	Base KV	Resistance R	Reactance X	Susceptance Ch	Overhead line cost (£)	Underground cable cost (£)	Rating (A)
5080	5081	275	0.00051	0.00475	0.0216433	0	0	1134
5080	5001	275	0.00054	0.00488	0.0333	0	0	1180
5080	5000	275	0.00054	0.00488	0.0333	0	0	1180
5081	5043	275	0.00051	0.00475	0.0216433	0	0	1134
5043	5040	275	0.00051	0.00475	0.0216433	0	0	1134
5001	5242	275	0.00062	0.005645	0.067725	0	0	1596
5242	5240	275	0.00062	0.005645	0.067725	0	0	1249
5008	5010	132	0.000745	0.04027	0	0	0	787.3
5009	5011	132	0.00049	0.040995	0	0	0	787.3
5010	2280	132	0.000849	0.002998	0.01542894	416,508	297,000	875
5010	2301	132	0.006153	0.029926	0.0192307	3,900,732	247,500	875
5011	2302	132	0.006153	0.029926	0.0192307	3,900,732	247,500	875
5011	2281	132	0.000812	0.002852	0.01039887	416,508	194,150	875
2724	2725	11	0	0.164	0	0	0	2361.9
2727	2726	11	0	0.229	0	0	0	2361.9
2281	2270	132	0.003478	0.016965	0.004087826	2,237,578	0	950
2300	2731	132	0.000574	0.000895	0.0328434	0	0	550
2300	2740	132	0.000113	0.000352	0.000550508	0	0	1610
2300	2271	132	0.003227	0.010002	0.005766788	1,300,148	121,000	705
2300	2730	132	0.000574	0.000895	0.0328434	0	0	550
2300	2301	132	0.002906	0.009017	0.003525637	1,193,720	0	805
2301	3834	132	0.002058	0.010041	0.002419379	1,324,310	0	950
2302	2330	132	0.002058	0.010041	0.002419379	1,324,310	0	950
13	2735	11	0	0.0001	0	0	0	2000
2740	2742	132	0	0.00011	0	0	0	2000
2740	2741	132	0	0.00011	0	0	0	2000
2747	2748	11	0	0.6637	0	0	0	2000
14	2745	11	0	0.0001	0	0	0	20000

15	2746	11	0	0.0001	0	0	0	20000
2739	2749	6.6	0	0.0001	0	0	0	2000
2812	2747	11	0.00925	0.02021	0	0	0	1259.7
2271	2270	132	0	0.0001	0	0	0	787
2290	2271	132	0.005925	0.032708	0.09481407	4,152,420	2,132,350	787
5050	2660	132	0.000929	0.004228	0.003962346	0	2,341,900	840
5050	2290	132	0.001947	0.006534	0.1549899	0	3,822,500	787
5051	5050	132	0.00046	0.04377	0	0	0	1049.73
5052	5050	132	0.00046	0.04377	0	0	0	1049.73
2360	5050	132	0.004105	0.009309	0.002005953	1,158,340	0	590
2361	5050	132	0.004105	0.009309	0.002005953	1,158,340	0	590
2320	5050	132	0.000702	0.002401	0.06880654	0	1,610,400	787
2320	2751	132	0	0.0001	0.000806696	0	0	623.2
2320	2750	132	0	0.0001	0.001656998	0	0	623.2
2755	2757	11	0.013157	0.01697	0.00096724	0	0	1800
2756	2757	11	0.013157	0.01697	0.00096724	0	0	1800
2350	2660	132	0.000405	0.001951	0.0210707	0	1,008,150	978.5
2350	2320	132	0.000399	0.001565	0.04808288	0	1,006,500	672
2330	2320	132	0.001031	0.003523	0.1009539	0	2,362,800	787
3834	2310	132	0.000346	0.001355	0.04164556	0	871,750	760
2310	2350	132	0.000876	0.003433	0.1054933	0	2,208,250	760
5250	2805	132	0.001291	0.005492	0.002025074	704,726	0	840
5250	2804	132	0.001291	0.005492	0.002025074	704,726	0	840
5250	2803	132	0.003474	0.015439	0.005692526	1,981,000	0	840
5250	2802	132	0.00369	0.015933	0.007142009	2,034,502	35,200	569
5250	2401	132	0.003996	0.016861	0.01790029	2,131,438	260,150	770
5250	2400	132	0.004	0.016871	0.0183733	2,131,438	270,600	770
5251	5250	132	0.000485	0.04229	0	0	0	971
5252	5250	132	0.00005	0.04221	0	0	0	1049.73
2802	2382	132	0.009552	0.021663	0.004667939	2,695,506	0	590
2382	2093	132	0.01293	0.029325	0.006318728	3,648,757	0	590
2093	2370	132	0.015055	0.034145	0.007357321	4,248,493	0	590
2803	2381	132	0.010463	0.02373	0.005113263	2,952,660	0	590
2381	2092	132	0.01293	0.029325	0.006318728	3,648,757	0	590
2370	2390	132	0.002948	0.006686	0.00144058	831,865	0	590
2371	2391	132	0.002948	0.006686	0.00144058	831,865	0	590
2092	2371	132	0.015055	0.034145	0.007357321	4,248,493	0	590
17	4449	11	0.628	0.2792	0	0	0	378
17	4446	11	0.557	0.2655	0	0	0	360
2804	2410	132	0.001019	0.002312	0.000498126	287,643	0	590
2804	2800	132	0.000366	0.001558	0.00057446	199,912	0	520
2805	2411	132	0.001019	0.002312	0.000498126	287,643	0	590
2805	2801	132	0.000366	0.001558	0.00057446	199,912	0	520
2800	2808	132	0.002021	0.003622	0.02626545	0	2,030,050	450
2801	2809	132	0.002021	0.003622	0.02626545	0	2,030,050	450
2400	2403	132	0.00068	0.003648	0.1048135	0	2,171,400	366
2401	2404	132	0.000675	0.00362	0.104017	0	2,154,900	366
2406	19	11	0	0.0001	0	0	0	2000
2403	2418	132	0.005801	0.016713	0.01853552	2,046,295	289,300	366
2404	2419	132	0.005806	0.016737	0.01922578	2,046,295	303,600	366
2420	2416	132	0	0.0001	0	0	0	65535

2418	2420	132	0	0.0001	0	0	0	65535
2419	2421	132	0	0.0001	0	0	0	65535

Table B.6: Transformer data

From	Base KV	To	Base KV	Resistance R	Reactance X	Susceptance Ch	Related cost (£)	Rating (MVA)
5000	275	5008	132	0.000745	0.04027	0	1,452,000	180
5000	275	5009	132	0.00049	0.040995	0	1,452,000	180
2280	132	2	33	0.01127	0.2898	0	1,391,069	45
5010	132	2724	11	0	0.164	0	0	45
5011	132	2727	11	0	0.229	0	0	45
2300	132	4	11	0.0225	0.8583	0	1,125,908	30
2300	132	4	11	0.0229	0.8613	0	1,125,908	30
2730	132	2735	11	0.0135	0.486	0	0	35
2731	132	2735	11	0.0135	0.486	0	0	35
2740	132	2812	11	0.00925	0.02021	0	0	24
2741	132	2745	11	0.00189	0.0767	0	0	180
2742	132	2746	11	0.00319	0.1382	0	0	92
2747	11	2749	6.6	0	0.6613	0	0	1
2270	132	1	33	0.0094	0.257	0	1,330,159	60
2270	132	1	33	0.01	0.213	0	1,330,159	60
2290	132	3	33	0.0065	0.2507	0	1,818,699	90
5050	132	9	11	0.0302	0.741	0	967,751	30
5050	132	8	33	0.0047	0.2033	0	1,724,111	90
5050	132	9	11	0.0304	0.745	0	967,751	30
5050	132	8	33	0.0048	0.2023	0	1,724,111	90
5040	275	5051	132	0.00046	0.04377	0	2,010,538	240
5040	275	5052	132	0.00046	0.04377	0	2,010,538	240
2360	132	11	11	0.024	0.86	0	1,164,556	30
2361	132	11	11	0.0265	0.8327	0	1,164,556	30
2320	132	6	33	0.0052	0.2712	0	2,190,551	90
2750	132	2755	11	0.0293	0.4167	0	0	30
2751	132	2756	11	0.0293	0.4167	0	0	30
2660	132	12	11	0.0192	0.851	0	1,029,211	30
2660	132	12	11	0.0192	0.851	0	1,029,211	30
2350	132	10	11	0.019	0.699	0	1,169,285	40
2350	132	10	11	0.019	0.6965	0	1,169,285	40
2330	132	7	33	0.0107	0.212	0	1,453,321	60
2330	132	7	33	0.0107	0.21	0	1,453,321	60
2310	132	5	11	0.0192	0.851	0	1,077,633	30
2310	132	5	11	0.0192	0.851	0	1,077,633	30
5250	132	22	11	0.0254	0.8607	0	951,610	30
5250	132	22	11	0.0231	0.8567	0	951,610	30
5240	275	5251	132	0.000485	0.04229	0	4,230,232	222
5240	275	5252	132	0.00005	0.04221	0	4,573,224	240
2370	132	16	33	0.0106	0.2738	0	1,072,604	45
2371	132	16	33	0.0117	0.2778	0	1,072,604	45
2390	132	17	11	0.03	0.893	0	943,540	30
2391	132	17	11	0.03	0.888	0	943,540	30

2381	132	23	33	0.0128	0.2733	0	1,671,673	45
2410	132	20	11	0.0254	0.8607	0	935,469	30
2411	132	20	11	0.0231	0.8567	0	935,469	30
2808	132	24	11	0.02125	0.8597	0	903,188	30
2809	132	24	11	0.02082	0.85905	0	903,188	30
2400	132	19	11	0.0297	0.89217	0	1,019,531	30
2401	132	19	11	0.0211	0.86244	0	1,019,531	30
2403	132	18	11	0.02614	0.86761	0	1,103,593	30
2404	132	18	11	0.0261	0.8423	0	1,103,593	30
2420	132	21	11	0.0234	0.83567	0	1,172,626	30
2421	132	21	11	0.0234	0.844	0	1,172,626	30

The power flow result of distribution test system is following:

Bus Data

Bus	V(pu)	V(kV)	V(theta)	Pg(MW)	Qg(MVAr)	Pd(MW)	Qd(MVAr)	LoadPf
5001	1.03	282.42	-0.46	0	0	0.00	0.00	----
5043	1.03	282.47	-0.49	0	0	0.00	0.00	----
5080	1.03	283.25	0.00	355.88	79.32	0.00	0.00	----
5081	1.03	282.87	-0.25	0	0	0.00	0.00	----
5242	1.02	281.40	-0.99	0	0	0.00	0.00	----
2270	1.04	137.70	-1.91	0	0	0.00	0.00	----
2271	1.04	137.70	-1.91	0	0	0.00	0.00	----
1	1.02	33.65	-4.12	0	0	34.77	3.47	1.00
2280	1.04	137.27	-1.76	0	0	0.00	0.00	----
2281	1.04	137.59	-2.00	0	0	0.00	0.00	----
2	1.03	34.08	-5.30	0	0	24.59	17.42	0.82
2290	1.04	136.61	-2.96	0	0	0.00	0.00	----
3	1.03	33.97	-8.26	0	0	40.11	6.61	0.99
2300	1.05	138.37	-1.37	0	0	0.00	0.00	----
2301	1.04	137.53	-1.94	0	0	0.00	0.00	----
2302	1.04	136.64	-2.80	0	0	0.00	0.00	----
4	1.05	11.50	-5.83	0	0	20.70	8.20	0.93
2310	1.04	136.74	-2.76	0	0	0.00	0.00	----
5	1.04	11.46	-7.32	0	0	21.00	6.10	0.96
2320	1.03	136.43	-3.02	0	0	0.00	0.00	----
6	1.02	33.67	-7.81	0	0	32.55	3.01	1.00
2330	1.03	136.33	-3.07	0	0	0.00	0.00	----
7	1.03	34.11	-7.44	0	0	81.18	27.07	0.95
8	1.03	33.86	-8.42	0	0	102.63	36.33	0.94
9	1.05	11.53	-8.53	0	0	29.80	8.70	0.96
2350	1.03	136.50	-2.97	0	0	0.00	0.00	----
10	1.05	11.53	-8.27	0	0	30.50	10.00	0.95
2360	1.03	136.38	-3.04	0	0	0.00	0.00	----
2361	1.03	136.38	-3.04	0	0	0.00	0.00	----
11	1.04	11.48	-4.67	0	0	7.40	1.50	0.98
2660	1.03	136.47	-2.99	0	0	0.00	0.00	----

12	1.04	11.48	-4.71	0	0	7.80	1.60	0.98
2724	1.04	11.45	-1.73	0	0	0.00	0.00	----
2725	1.04	11.45	-1.73	0	0	0.00	0.00	----
2726	1.04	11.46	-2.01	0	0	0.00	0.00	----
2727	1.04	11.46	-2.01	0	0	0.00	0.00	----
2730	1.05	138.39	-1.37	0	0	0.00	0.00	----
2731	1.05	138.39	-1.37	0	0	0.00	0.00	----
2735	1.06	11.61	2 73	0	0	0.00	0.00	----
13	1.06	11.61	2.73	0	0	-32.30	-10.62	-0.95
14	1.01	11.14	6.25	0	0	-171.00	-56.21	-0.95
15	1.01	11.13	3.17	0	0	-57.00	-18.74	-0.95
2739	1.05	6.92	-1.33	0	0	0.00	0.00	----
2740	1.05	138.42	-1.33	0	0	0.00	0.00	----
2741	1.05	138.43	-1.32	0	0	0.00	0.00	----
2742	1.05	138.43	-1.33	0	0	0.00	0.00	----
2745	1.01	11.14	6.24	0	0	0.00	0.00	----
2746	1.01	11.13	3.16	0	0	0.00	0.00	----
2747	1.05	11.54	-1.33	0	0	0.00	0.00	----
2748	1.05	11.54	-1.33	0	0	0.00	0.00	----
2749	1.05	6.92	-1.33	0	0	0.00	0.00	----
2750	1.03	136.43	-3.02	0	0	0.00	0.00	----
2751	1.03	136.43	-3.02	0	0	0.00	0.00	----
2755	1.05	11.57	-3.02	0	0	0.00	0.00	----
2756	1.05	11.57	-3.02	0	0	0.00	0.00	----
2757	1.05	11.57	-3.02	0	0	0.00	0.00	----
2812	1.05	11.54	-1.33	0	0	0.00	0.00	----
3834	1.04	136.85	-2.66	0	0	0.00	0.00	----
5000	1.03	282.88	-0.20	0	0	0.00	0.00	----
5008	1.05	137.95	-0.96	0	0	0.00	0.00	----
5009	1.05	138.04	-1.10	0	0	0.00	0.00	----
5010	1.04	137.37	-1.73	0	0	0.00	0.00	----
5011	1.04	137.56	-2.01	0	0	0.00	0.00	----
5040	1.03	282.04	-0.74	0	0	0.00	0.00	----
5050	1.03	136.41	-3.02	0	0	0.00	0.00	----
5051	1.04	137.02	-1.88	0	0	0.00	0.00	----
5052	1.04	137.02	-1.88	0	0	0.00	0.00	----
2092	0.99	130.34	-6.81	0	0	0.00	0.00	----
2093	0.99	131.08	-6.66	0	0	0.00	0.00	----
2370	0.98	129.90	-7.16	0	0	0.00	0.00	----
2371	0.98	129.30	-7.30	0	0	0.00	0.00	----
16	1.03	34.10	-9.54	0	0	32.35	12.07	0.94
2381	0.99	131.20	-6.39	0	0	0.00	0.00	----
2382	1.00	132.08	-6.24	0	0	0.00	0.00	----
2390	0.98	129.80	-7.20	0	0	0.00	0.00	----
2391	0.98	129.21	-7.35	0	0	0.00	0.00	----
17	1.03	11.36	-13.26	0	0	26.10	6.50	0.97
2400	1.01	133.05	-5.94	0	0	0.00	0.00	----
2401	1.01	133.04	-5.95	0	0	0.00	0.00	----
18	1.05	11.57	-9.24	0	0	15.30	6.00	0.93
2403	1.01	133.03	-5.98	0	0	0.00	0.00	----

2404	1.01	133.02	-5.98	0	0	0.00	0.00	----
19	1.05	11.58	-11.10	0	0	24.00	9.50	0.93
2406	1.05	11.58	-11.10	0	0	0.00	0.00	----
2410	1.01	133.13	-5.73	0	0	0.00	0.00	----
2411	1.01	133.13	-5.73	0	0	0.00	0.00	----
20	1.06	11.61	-9.15	0	0	16.00	5.30	0.95
2416	1.01	132.90	-6.05	0	0	0.00	0.00	----
2418	1.01	132.90	-6.05	0	0	0.00	0.00	----
2419	1.01	132.89	-6.05	0	0	0.00	0.00	----
2420	1.01	132.90	-6.05	0	0	0.00	0.00	----
2421	1.01	132.89	-6.05	0	0	0.00	0.00	----
21	1.05	11.53	-9.56	0	0	16.70	6.60	0.93
22	1.06	11.61	-10.73	0	0	23.00	0.00	1.00
2800	1.01	133.15	-5.72	0	0	0.00	0.00	----
2801	1.01	133.15	-5.72	0	0	0.00	0.00	----
2802	1.01	132.80	-5.93	0	0	0.00	0.00	----
2803	1.00	132.52	-5.99	0	0	0.00	0.00	----
2804	1.01	133.15	-5.72	0	0	0.00	0.00	----
2805	1.01	133.15	-5.72	0	0	0.00	0.00	----
2808	1.01	133.13	-5.73	0	0	0.00	0.00	----
2809	1.01	133.13	-5.73	0	0	0.00	0.00	----
23	1.03	33.87	-7.97	0	0	11.67	13.88	0.64
24	1.06	11.66	-8.18	0	0	11.50	4.60	0.93
4446	1.03	11.36	-13.26	0	0	0.00	0.00	----
4449	1.03	11.36	-13.26	0	0	0.00	0.00	----
5240	1.02	280.30	-1.53	0	0	0.00	0.00	----
5250	1.01	133.19	-5.68	0	0	0.00	0.00	----
5251	1.02	134.46	-3.58	0	0	0.00	0.00	----
5252	1.02	134.46	-3.58	0	0	0.00	0.00	----

Line Data

FromBus	ToBus	V(kV)	Pij(MW)	Qij(MVAr)	Pji(MW)	Qji(MVAr)	PLoss(MW)	Util%
5080	5081	275	98.35	18.32	-98.30	-20.16	0.05	18.50
5080	5001	275	178.85	42.93	-178.68	-44.89	0.17	32.80
5080	5000	275	78.69	18.07	-78.65	-21.29	0.03	14.40
5081	5043	275	98.30	20.16	-98.25	-21.99	0.05	18.60
5043	5040	275	98.25	21.99	-98.20	-23.82	0.05	18.70
5001	5242	275	178.68	44.89	-178.48	-50.17	0.20	24.30
5242	5240	275	178.48	50.17	-178.27	-55.36	0.21	31.30
5008	5010	132	36.39	11.00	-36.38	-10.46	0.01	21.10
5009	5011	132	42.24	9.06	-42.24	-8.36	0.01	24.00
5010	2280	132	24.69	18.24	-24.69	-19.89	0.01	15.60
5010	2301	132	11.69	-7.78	-11.68	5.75	0.01	6.80
5011	2302	132	52.45	12.77	-52.29	-14.03	0.17	27.00
5011	2281	132	-10.22	-4.40	10.22	3.28	0.00	5.50
2724	2725	11	0.00	0.00	0.00	0.00	0.00	0.00
2727	2726	11	0.00	0.00	0.00	0.00	0.00	0.00
2281	2270	132	-10.22	-3.28	10.22	2.85	0.00	4.90
2300	2731	132	-16.11	-7.65	16.12	4.05	0.00	13.70

2300	2740	132	-227.24	-45.67	227.29	45.78	0.06	63.00
2300	2271	132	108.66	18.43	-108.30	-17.95	0.36	68.20
2300	2730	132	-16.11	-7.65	16.12	4.05	0.00	13.70
2300	2301	132	130.05	32.40	-129.57	-31.31	0.48	72.60
2301	3834	132	141.25	25.56	-140.86	-23.92	0.39	65.90
2302	2330	132	52.29	14.03	-52.23	-14.01	0.06	24.90
13	2735	11	32.30	10.61	-32.30	-10.61	0.00	89.20
2740	2742	132	-56 89	-13.86	56.89	13.87	0.00	12.80
2740	2741	132	-170.40	-31.92	170.40	31.95	0.00	37.90
2747	2748	11	0.00	0.00	0.00	0.00	0.00	0.00
14	2745	11	171.00	56.21	-171.00	-56.17	0.00	47.24
15	2746	11	57.00	18.74	-57.00	-18.73	0.00	15.75
2739	2749	6.6	0.00	0.00	0.00	0.00	0.00	0.00
2812	2747	11	0.00	0.00	0.00	0.00	0.00	0.00
2271	2270	132	45.05	7.69	-45.05	-7.69	0.00	25.40
2290	2271	132	-63.02	-19.22	63.25	10.26	0.23	36.10
5050	2660	132	-15.51	-6.70	15.51	6.29	0.00	8.80
5050	2290	132	-22.80	-25.23	22.81	8.70	0.01	16.20
5051	5050	132	49.09	10.88	-49.08	-9.85	0.01	20.90
5052	5050	132	49.09	10.88	-49.08	-9.85	0.01	20.90
2360	5050	132	-3.64	-0.85	3.64	0.64	0.00	2.80
2361	5050	132	-3.76	-0.87	3.76	0.65	0.00	2.80
2320	5050	132	3.78	2.02	-3.78	-9.36	0.00	4.00
2320	2751	132	0.00	-0.19	0.00	0.11	0.00	0.10
2320	2750	132	0.00	-0.28	0.00	0.11	0.00	0.10
2755	2757	11	0.00	-0.11	0.00	0.00	0.00	0.20
2756	2757	11	0.00	-0.11	0 00	0.00	0.00	0.20
2350	2660	132	23.32	5.90	-23.31	-8.14	0.00	10.90
2350	2320	132	65.73	11.81	-65.71	-16.88	0.02	43.80
2330	2320	132	-29.32	-20.29	29.33	9.55	0.01	18.50
3834	2310	132	140.86	23.92	-140.80	-28.13	0.07	82.40
2310	2350	132	119.75	20.16	-119.63	-30.98	0.12	70.50
5250	2805	132	13.79	2.84	-13.79	-3.03	0.00	7.30
5250	2804	132	13.76	2.80	-13.76	-2.99	0.00	7.30
5250	2803	132	40.76	23.91	-40.68	-24.14	0.08	24.60
5250	2802	132	30.60	11.31	-30.56	-11.87	0.04	25.10
5250	2401	132	28.35	-0.50	-28.32	-1.18	0.03	16.10
5250	2400	132	27.87	-0.91	-27.84	-0.83	0.03	15.80
5251	5250	132	89.15	23.73	-89.11	-20.26	0.04	41.40
5252	5250	132	89.08	24.69	-89.07	-21.22	0.00	38.30
2802	2382	132	30.56	11.87	-30.46	-12.10	0.10	24.30
2382	2093	132	30.46	12.10	-30.32	-12.42	0.14	24.30
2093	2370	132	30.32	12.42	-30.15	-12.76	0.17	24.30
2803	2381	132	40.68	24.14	-40.45	-24.12	0.23	35.00
2381	2092	132	28.74	9.39	-28.62	-9.74	0.12	22.40
2370	2390	132	13.27	4.94	-13.26	-5.06	0.01	10.50
2371	2391	132	12.95	4.33	-12.94	-4.46	0.01	10.10
2092	2371	132	28.62	9.74	-28.47	-10.13	0.14	22.40
17	4449	11	0.00	0.00	0.00	0.00	0.00	0.00
17	4446	11	0.00	0.00	0.00	0.00	0.00	0.00

2804	2410	132	8.00	3.13	-8.00	-3.18	0.00	6.40
2804	2800	132	5.76	-0.14	-5.76	0.08	0.00	4.80
2805	2411	132	8.03	3.17	-8.03	-3.22	0.00	6.40
2805	2801	132	5.76	-0.13	-5.76	0.08	0.00	4.80
2800	2808	132	5.76	-0.08	-5.76	-2.59	0.00	5.90
2801	2809	132	5.76	-0.08	-5.76	-2.60	0.00	5.90
2400	2403	132	15.98	-5.09	-15.97	-5.55	0.00	20.10
2401	2404	132	16.10	-5.04	-16.10	-5.52	0.00	20.30
2406	19	11	0.00	0.00	0.00	0.00	0.00	0.00
2403	2418	132	8.42	2.07	-8.41	-3.94	0.00	10.70
2404	2419	132	8.33	1.96	-8.32	-3.89	0.00	10.60
2420	2416	132	0.00	0.00	0.00	0.00	0.00	0.00
2418	2420	132	8.41	3.94	-8.41	-3.94	0.00	0.10
2419	2421	132	8.32	3.89	-8.32	-3.89	0.00	0.10

Transformer Data

FromBus	ToBus	Pij(MW)	Qij(MVAr)	Pji(MW)	Qji(MVAr)	PLoss(MW)	Util%	TapRatio
5000	5008	36.40	11.53	-36.39	-11.00	0.01	21.20	0.98
5000	5009	42.25	9.76	-42.24	-9.06	0.01	24.00	0.98
2280	2	24.69	19.89	-24.59	-17.42	0.10	68.70	0.96
5010	2724	0.00	0.00	0.00	0.00	0.00	0.00	1.00
5011	2727	0.00	0.00	0.00	0.00	0.00	0.00	1.00
2300	4	10.39	5.09	-10.37	-4.11	0.03	37.90	0.97
2300	4	10.36	5.06	-10.33	-4.09	0.03	37.70	0.97
2730	2735	-16.12	-4.05	16.15	5.31	0.04	48.00	1.02
2731	2735	-16.12	-4.05	16.15	5 31	0.04	48.00	1.02
2740	2812	0.00	0.00	0.00	0.00	0.00	0.00	1.00
2741	2745	-170.40	-31.95	171.00	56.17	0.60	98.20	1.08
2742	2746	-56.89	-13.87	57.00	18.73	0.11	64.40	1.06
2747	2749	0.00	0.00	0.00	0.00	0.00	0.00	1.00
2270	1	15.77	2.28	-15.75	-1.66	0.02	26.50	1.02
2270	1	19.05	2.56	-19.02	-1.81	0.04	31.90	1.02
2290	3	40.21	10.52	-40.11	-6.61	0.10	45.70	0.98
5050	9	15.01	6.00	-14.94	-4.36	0.07	52.90	0.95
5050	8	51.31	23.83	-51.18	-18.14	0.13	61.60	0.97
5050	9	14.93	5.96	-14.86	-4.34	0.07	52.60	0.95
5050	8	51.58	23.92	-51.45	-18.19	0.14	61.90	0.97
5040	5051	49.10	11.91	-49.09	-10.88	0.01	21.00	0.98
5040	5052	49.10	11.91	-49.09	-10.88	0.01	21.00	0.98
2360	11	3.64	0.85	-3.64	-0.75	0.00	12.40	0.98
2361	11	3.76	0.87	-3.76	-0.75	0.00	12.80	0.98
2320	6	32.60	5.79	-32.55	-3.01	0.05	36.60	1.00
2750	2755	0.00	-0.11	0.00	0.11	0.00	0.40	0.98
2751	2756	0.00	-0.11	0.00	0.11	0.00	0.40	0.98
2660	12	3.90	0.92	-3.90	-0.80	0.00	13.30	0.98
2660	12	3.90	0.92	-3.90	-0.80	0.00	13.30	0.98
2350	10	15.27	6.63	-15.22	-4.99	0.04	40.80	0.95
2350	10	15.32	6.65	-15.28	-5.01	0.04	41.00	0.95
2330	7	40.58	17.08	-40.39	-13.48	0.18	72.20	0.97

2330	7	40.97	17.22	-40.79	-13.59	0.19	72.90	0.97
2310	5	10.52	3.99	-10.50	-3.05	0.02	37.00	0.97
2310	5	10.52	3.99	-10.50	-3.05	0.02	37.00	0.97
5250	22	11.50	1.00	-11.47	0.01	0.03	38.40	0.95
5250	22	11.55	1.04	-11.53	-0.01	0.03	38.50	0.95
5240	5251	89.19	27.20	-89.15	-23.73	0.04	41.80	0.99
5240	5252	89.08	28.17	-89.08	-24.69	0.00	38.70	0.99
2370	16	16.89	7.82	-16.85	-6.97	0.03	40.90	0.93
2371	16	15.53	5.79	-15.50	-5.10	0.03	36.50	0.93
2390	17	13.26	5.06	-13.21	-3.50	0.05	46.40	0.92
2391	17	12.94	4.46	-12.89	-3.00	0.05	44.90	0.92
2381	23	11.71	14.73	-11.67	-13.88	0.04	41.10	0.93
2410	20	8.00	3.18	-7.98	-2.63	0.02	28.40	0.93
2411	20	8.03	3.22	-8.02	-2.67	0.01	28.50	0.93
2808	24	5.76	2.59	-5.75	-2.30	0.01	20.80	0.93
2809	24	5.76	2.60	-5.75	-2.30	0.01	20.90	0.93
2400	19	11.86	5.92	-11.82	-4.62	0.04	43.20	0.92
2401	19	12.21	6.22	-12.18	-4.88	0.03	44.70	0.92
2403	18	7.56	3.48	-7.54	-2.96	0.02	27.40	0.93
2404	18	7.78	3.56	-7.76	-3.04	0.02	28.10	0.93
2420	21	8.41	3.94	-8.40	-3.32	0.02	30.50	0.93
2421	21	8.32	3.89	-8.30	-3.28	0.02	30.20	0.93

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OPTIMAL ECONOMIC ENVIRONMENTAL DISPATCH CONSIDERING WHEELING CHARGE

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ABSTRACT

This paper presents the application of genetic algorithms (GA) to the economic environmental dispatch problem, considering transmission (or wheeling) charges. Traditional approach to economic dispatch is purely based on fuel costs. With increasing emphasis on environmental protection and system security, it is economically efficient for a generation company to consider the level of emissions and cost of wheeling when dispatching power. Fuel cost and emissions produced from a unit are generally related only to the amount of power to be produced. Wheeling charges, however are not only dependent on the amount of power to be transferred, but also closely linked to the network configuration and network traffic at the time, hence highly non-linear. This paper proposes a genetic algorithm based optimisation technique to take into account these non-linearities, providing a useful tool for generation companies to dispatch power at the least possible cost and the minimum levels of pollution, where the cost to be minimised includes both fuel and wheeling cost.

Keywords:
Genetic algorithms (GA), wheeling charges, economic and environmental dispatch

INTRODUCTION

The problem of Economic Dispatch (ED) is to schedule the power outputs for the on-line generators so that the total fuel cost is minimised and customer load demand is matched. Traditional approach to economic dispatch is purely based on the cost of power production [1]. This has to change in the deregulated environment. for that the users of the transmission system, i.e. generator companies and suppliers, have to pay for the use of the transmission system when wheeling electricity from one point of the network to another. This implies that under the deregulated environment the economic dispatch problem has to be extended to take into account of the additional wheeling charges. Coupled with increasing emphasis on environmental protection and system security, it is economically efficient for a generation company to consider level of emissions and cost of wheeling when dispatching power.

Economic Environmental Dispatch (EED) considering wheeling costs adds significant complication to the power dispatch problem. Fuel cost and emissions produced from a unit are generally related only to the amount of power to be produced. Wheeling charges, however are not only dependent on the amount of power to be transferred, but also closely linked to the network configuration and network traffic at the time, hence highly non-linear. This paper therefore proposes a genetic algorithm based optimisation technique to take into account these non-linearities, providing a useful tool for generation companies to dispatch power at the least possible cost and the minimum level of pollution, where the cost to be minimised includes both fuel and wheeling cost.

ENVIRONMENTAL ECONOMIC DISPATCH (EED) PROBLEM FORMULATION

EED Problem Definition

The aim of the EED problem is to supply the load demand while minimising the environmental impact at the minimum possible operating cost, including both fuel cost and wheeling cost [2].

The EED problem formulation considered in this paper can be mathematically stated as follows:

Problem objectives

1) Minimisation of fuel cost

Minimise $$C_f = \sum_{i=1}^{n} F_{Gi} \quad (1)$$

Where

$F_{Gi} = (a_{Gi} - b_{Gi} \cdot S_{Gi}) \cdot (\alpha_{Gi} + \beta_{Gi} \cdot P_{Gi} + \gamma_{Gi} \cdot P_{Gi}^2)$

a_{Gi}, b_{Gi} are the cost per kcal coefficients;

α_{Gi}, β_{Gi}, γ_{Gi} are fuel consumption coefficients;

S_{Gi} is the sulphur contents in fuels for the i th generator;

C_f is the total fuel cost from all generators.

2) Minimisation of wheeling cost

Minimise $$C_w = C_k L_k \cdot \sum P_{ij}^g \quad (2)$$

Where

P_{ij}^g is the loading at the ij th line caused by generator g;

$C_k L_k$ is the cost of k th transmission line, \$/MW;

C_w is the total wheeling cost.

The detail of the calculation methodology of wheeling charges will be introduced in the next section.

Constraints

1) Generation limit constraints

For the safety operation of a generation, power outputs from each generator must be within a limit:

$$P_{Gi}^{\min} \le P_{Gi} \le P_{Gi}^{\max} \tag{3}$$

Where P_{Gi} is the real power output of the i th generator, $P_{Gi}^{\min}$ is the lowest power output level where $P_{Gi}^{\max}$ is the highest output level.

2) Power balance constraints

The total power generation must be equal to the total power demand and power losses in the transmission lines:

$$\sum_{i=1}^{n} P_{Gi} - P_{Demand} - P_{Loss} = 0 \tag{4}$$

3) Emission limits

The total pollution generated in an area must be below the specified limit MS:

$$\sum_{i=1}^{n} Q_{Gi} \le MS \tag{5}$$

Where

$$Q_{Gi} = e_{Gi} \cdot S_{Gi} \cdot (\alpha_{Gi} + \beta_{Gi} \cdot P_{Gi} + \lambda_{Gi} \cdot P_{Gi}^2)$$

e_{Gi} is the coefficients of the i th generator emission

MS is the maximum air pollution allowance for a particular area.

Calculation Method of Wheeling Charges

The term of wheeling is defined as "The use of transmission or distribution facilities of a system to transmit power of and for another entity or entities." [3] Wheeling costs when applied to a transmission network, also called transmission costs, are the costs charged against generator companies and suppliers for their use of the transmission services. The simplest approach to the transmission pricing is the postage-stamp method [4], in which the wheeling customers will pay a fixed rate per unit of the energy transmitted regardless of their distance and location. This simple allocation method does not provide economic signals for market participants of congestion and constraint problems and needs for future network development. The MW-Mile methodology based on power flow is a more realistic measure of the actual use of a transmission network [3]. This paper adopts the Bialek's power tracing method to find individual generator's contribution to line power flow, based on which, the cost of transmission charges are allocated to each generator companies [5].

In Bialek's tracing method, it is assumed that nodal inflows are shared proportionally among nodal outflows, as shown in Figure 1.

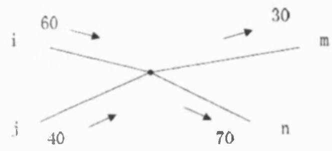

Figure 1: Proportional sharing principle

The wheeling charges are determined by topological distribution factor, which refers to the k^{th} generator's contribution to line *i-j*'s power flow, and defined by the following equations:

$$P_{ij}^{g} = \frac{P_{ij}^{g}}{P_i^{g}} \sum_{k=1}^{n} \left[\mathbf{A}_u^{-1}\right]_{ik} P_{GK} = \sum_{k=1}^{n} D_{ij,k}^{g} P_{GK} \; ; \; j \in \alpha_i^{d} \tag{6}$$

Where

$$P_i^{g} = \sum_{j \in \alpha_i^{u}} \left| P_{ij}^{g} \right| + P_{Gi} \; ; \; i = 1,2,\dots, n \tag{7}$$

$$[\mathbf{A}_u]_{ij} = \begin{cases} 1 & i = j \\ -\dfrac{\left|P_{ij}\right|}{P_j} & j \in \alpha_i^{u} \\ 0 & otherwise \end{cases} \tag{8}$$

$$D_{ij}^{g} = \frac{P_{ij}^{g} \left[\mathbf{A}_u^{-1}\right]_{ik}}{P_i^{g}} \cong \frac{P_{ij} \left[\mathbf{A}_u^{-1}\right]_{ik}}{P_i} \tag{9}$$

and

P_{ij}^{g} : an unknown gross line flow in line $i-j$

P_i^{g} : an unknown gross nodal power flow through node i

$\mathbf{A}_u$: topological distribution matrix

P_{GK} : generation in node k

α_i^{d} : set of nodes supplied directly from node i

α_i^{u} : set of buses supplying bus i

$D_{ij,k}^{g}$: topological distribution factors

Figure 2 is the flow diagram for the wheeling charge calculation based on the Bialek's power tracing method:

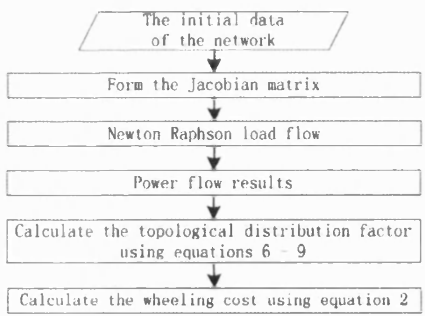

Figure 2: Flow chart of wheeling charges calculation

IMPLEMENTATION OF PROPOSED DISPATCH ALGORITHM

A number of optimisation techniques can be used for solving the EED problem: linear programming, genetic programming, dynamic programming, and simulated annealing. The variability and imprecise nature of this problem requires a robust optimisation technique that can handle complex problem formulations. Hence, Genetic algorithms have been chosen as the dispatch algorithm for the EED problem considering the wheeling cost.

The Mechanics of Genetic Algorithms

Genetic Algorithms (GA) are search algorithms based on the mechanics of natural selection and natural genetics. The original concept of GA is from the evolutionary behaviour of biological systems. The initial candidates are generated at random with little knowledge of correctness. Parameters of each solution guess are represented as bit strings instead of actual parameters, so that they can be improved repeatedly with a series of genetic operators, namely reproduction, crossover and mutation [6].

Genetic algorithms are general purposed techniques for optimisation and learning, and they are especially useful for multi-modal, multi-objective, highly non-linear, discontinuous search space.

Application Procedure of Genetic Algorithms for the EED Problem

The followings are the procedure of the proposed dispatch algorithm:

1. Setting up the test system;
2. Initialising the population. All generator outputs except the slack bus generator, are represented as bit strings to be optimised;
3. The bit strings are mapped into the range specified by the power limit constraints, generation costs, emission production, constraint violations can then be calculated;
4. Applying the Bialek's tracing methodology to calculate the wheeling cost for each population member, using the power outputs from the GA;
5. Calculating the fitness value according to the equation stated below:
$$FN=\frac{F_S}{F_{S\max}-F_{S\min}}+\eta\cdot\frac{F_{\pi}}{F_{\pi\max}-F_{\pi\min}}+\lambda\cdot\frac{\varphi}{\varphi_{\max}-\varphi_{\min}}+\mu\cdot\frac{\theta}{\theta_{\max}-\theta_{\min}}$$
Where,
F_S is the fuel cost objective;
F_{π} is the wheeling cost objective;
φ is the power balance constraint;
θ is the area emission constraint;
η, λ, μ are corresponding weight coefficients.
max, min are corresponding maximum and minimum limits.
6. According to the fitness value, the power output variables will be manipulated under the GA operators: reproduction, crossover and mutation [7].
7. Repeat the steps 3~ 5, until the convergent criteria is met.
8. The final result is the best among the whole population members.

TEST SYSTEM AND RESULTS

Figure 3 shows the test system with two generators and five buses [4]. The line data are given in Table 1. Bus 1 is assigned as the slack bus.

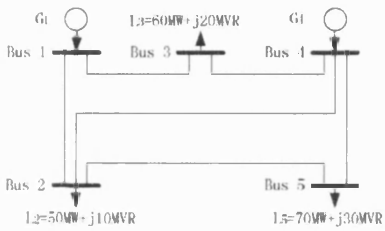

Figure 3: 5-bus test system

Table 1: System data of the 5-Bus Example

Line	From	To	R	X	B/2	C_kL_k
1	1	2	0.02	0.06	0.030	1.5
2	1	3	0.08	0.24	0.025	6
3	2	4	0.06	0.18	0.020	7
4	2	5	0.04	0.12	0.015	3
5	3	4	0.01	0.03	0.010	0.75
6	4	5	0.08	0.24	0.025	6

The cost and emission characteristics of G1 and G4 are summarised as below.

Fuel cost functions are:
$$F_{G1}=(3.21-0.36\cdot S_{G1})\cdot(148.4+2.21\cdot P_{G1}+0.25\cdot P_{G1}^2)$$
$$F_{G4}=(3.219-0.355\cdot S_{G4})\cdot(137.2+0.89\cdot P_{G4}+0.25\cdot P_{G4}^2)$$

Generation limit constraints are:
$$100MW\le P_{G1}\le 150MW$$
$$50MW\le P_{G4}\le 80MW$$

Area emission functions are:
$$Q_{G1}=0.673\cdot S_{G1}\cdot(148.4+2.21\cdot P_{G1}+0.25\cdot P_{G1}^2)$$
$$Q_{G4}=0.67\cdot S_{G4}\cdot(137.2+0.89\cdot P_{G4}+0.25\cdot P_{G4}^2)$$

The range of sulphur content of fuels are:
$$0.3\le S_{G1}\le 0.8$$
$$0.3\le S_{G4}\le 0.8$$

The parameters for the GA search algorithm are set as:

Total generation:	100
Population size:	100
Crossover probability:	0.9
Mutation rate:	0.03

Table 2 shows the simulation results under different emission limits. The results are the best from the five GA runs under each emission limit. As shown from the table, the more relaxed emission limits lead to the decreased fuel cost. Since generator 4 is the cheaper one of the two generators, it tends to operate at its maximum capacity, while the sulphur contents progressive increases with increases in the emission limit.

Table 2: Simulation result

Emission Limit (Nm^3/h)		225	250	275
G1	Output(MW)	103.36	103.36	103.36
	Sulphur (%)	0.54	0.74	0.75
	Fuel cost ($)	1140.18	1126.96	1125.86
	Emission	145.83	170.54	172.6
G4	Output(MW)	80	80	80
	Sulphur (%)	0.49	0.48	0.72
	Fuel cost ($)	635.19	635.8	626.77
	Emission	62.79	75.8	92.82
Total	Transmission cost ($)	642.23	642.23	642.23
	Fuel cost ($)	1775	1762	1752
	Cost ($)	2417.23	2404.23	2394.23

For the resultant power outputs from the GA search, the network's voltages, angles, generation and load at each busbars are shown in Table 3. The load flow result for each line is shown in Table 4. Table 5 gives the line loadings from each generator unit using Bialek's power tracing algorithm. Finally, table 6 shows the final transmission cost allocated to each generator.

Table 3: Voltage, Angle and Load at Each Bus

Bus	Voltage	Angle	P_L	Q_L	P_G	Q_G
1	1.060	0.000	0	0	103.36	14.52
2	1.035	-2.452	50	10	0.00	0.00
3	1.042	-2.283	60	20	0.00	0.00
4	1.050	-1.712	0	0	80.00	28.57
5	0.999	-4.912	70	30	0.00	0.00
Total			180	60	183.36	43.09

Table 4: Line Flow Results

Line	From	To	P_{ij} (MV)	Q_{ij} (MVA)
1	1	2	84.34	15.22
2	1	3	19.02	-0.70
3	2	4	-9.66	-7.77
4	2	5	42.68	15.59
5	3	4	-41.24	-15.96
6	4	5	28.85	10.63

Table 5: Transmission Usage Allocation

Line	From	To	Contribution from G1(MW)	Contribution from G4(MW)
1	1	2	84.343	0
2	1	3	19.017	0
3	2	4	0	9.929
4	2	5	38.292	4.388
5	3	4	0	41.331
6	4	5	0	28.846

Table 6: Transmission Charge Allocation

Line	From	To	C_kL_k($/MW)	G1($)	G4($)
1	1	2	1.5	126.51	0
2	1	3	6	114.10	0
3	2	4	7	0	69.50
4	2	5	3	114.88	13.16
5	3	4	0.75	0	31.00
6	4	5	6	0	173.08
Total				355.49	286.74
				642.23	

CONCLUSIONS

This paper uses genetic algorithms as the dispatch algorithm for the economic environmental dispatch problem, considering the wheeling charges. The wheeling charges are calculated with a power flow based MW-Mile approach, where the power tracing from each generator is carried out using the Bialek's tracing method. The proposed dispatch algorithm is tested on a small test system, showing that the GA is capable of dealing with non-linear and multi-objective problems. The dispatch algorithm can be scaled up as a useful tool for generation companies to dispatch power at the least possible cost and the minimum levels of pollution, where the cost to be minimised includes both fuel and wheeling cost.

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RELIABILITY CONSTRAINED OPTIMAL POWER FLOW

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Keywords: Optimal power flow, reliability index, multi-objective genetic algorithms.

Abstract

The paper presents a multi-objective genetic algorithm (MOGA) to determine optimal power flow (OPF) with extended objectives. The extended OPF problem is formulated to more closely reflect the actual system operation that respects the environmental restrictions, the cost of use of transmission network and the desire for a reliable system. The more realistic modelling of the reliability constraints optimal power flow (RCOPF) assigns generation cost, transmission cost, generation reliability indices, security objective and emission as five independent. The paper then develops a MOGA that is able to simultaneously optimise the aforementioned five objectives. This is contrary to the more popular approach of optimising a single performance index made of a linear combination of various objectives. The effectiveness of the proposed algorithm is tested on the IEEE 30-bus system.

1 Introduction

The classical optimal power flow (OPF) is to obtain the least cost generation pattern that can respect the security constraints of the transmission network while meeting system demands [4,5,9]. These calculations often ignore the cost of the use of the transmission network, and fail to take into account of the emission constraints and system reliability. This paper firstly aims to develop a more realistic modelling of the reliability constraints optimal power flow (RCOPF), assigning generation cost, transmission cost, security, emission, and reliability indices as five independent objectives to be optimised. The paper then develops a MOGA that is able to simultaneously optimise the aforementioned five objectives, attaining a set of non-inferior solutions. Compared with the more popular approach of optimising a single performance index made of a linear combination of various objectives. MOGA can offer a wide range of options to choose from [1,8]. Especially, over the planning process, MOGA allows more options to be examined in order to strike a right balance between cost, security and reliability.

Reliability refers to the probability of its satisfactory operation under uncertainties conditions [6]. Generator outages, which are one of the most important indices of system reliability, refer to the possible loss of a certain generator during a period. This paper introduces a reliabilit index based on generator outage that is incorporated into th OPF calculation to improve system reliability in addition t minimising generation cost, transmission cost an environmental impact.

The effectiveness of the proposed MOGA and implication o the new OPF modelling are demonstrated on the IEEE 30-bu 6-generator system [11]. The MOGA is able to generate a se of non-inferior solutions and their respective strength providing a valuable assessment for the planner or systen operator to choose from.

2 Formulation of RCOPF

The propos of the RCOPF calculation is to supply the loa demand while minimising the environmental impact maximising system reliability at the minimum possibl operating cost, including both fuel cost and wheeling cost.

2.1 Introduce the reliability index

Reliability is "the degree to which the performance of th elements of that system results in power being delivered t consumers within accepted standards and in the amount o desired" [6]. In general, reliability include adequacy whicl means the ability of the generator supply the custome without scheduled and unscheduled outage, and securit which means the ability of the system withstand sudde disturbances.

According to the preference index, which introduced in th reference paper [16], reliability index indicated the systen reliability based on the generator outage, which is showed i equation (1).

$$I = \sum_{i=1}^{N} R_i \cdot \sum_{k=1}^{L} l_k(P_i) \qquad (1)$$

$$R_i = (1-r_1)(1-r_2)\ldots r_i\ldots(1-r_n) \qquad (2)$$

$$l_k(P_i) = f(P_{lk}^{'} - \overline{P_{lk}}) \qquad (3)$$

$$f(x_i) = |x_i| \qquad x_i \in \phi \qquad (4)$$

Where,

r_i : Forced outage rates of generator i;

$P_{lk}^{'}$: Power flow of transmission line k before an outage;

$\overline{P_{lk}}$: Permissible value of transmission line k;

ϕ: A series of transmission lines that power flow exceed their permissible values.

The reliability index will be a small value, which is not a real indicator from the practice system. But it take into account of not only the outage rates of generator to avoid the system emergency and show the adequacy ability, but also the power system line load profiles to meet the system security. The minimum preference means the higher reliability of the system. Compared with the reliability indices of different system status, the system operator can detect the risk of a particular power dispatch.

2.2 RCOPF objectives

2.2.1 Minimisation of fuel cost

Minimize $C_f = \sum_{i=1}^{N} F_{Gi}$ (5)

Where

$F_{Gi} = \alpha_{Gi} \cdot P_{Gi}^2 + \beta_{Gi} \cdot P_{Gi} + \gamma_{Gi}$: Fuel cost of the *i*th generator, \$/h;

$\alpha_{Gi}, \beta_{Gi}, \gamma_{Gi}$: Fuel consumption coefficients;

C_f: Total fuel cost from all generators.

2.2.2 Minimization of transmission cost

Transmission cost, also called wheeling cost, means the usage cost of transmission and distribution facility charged against suppliers and consumers. The MW-Mile methodology based on power flow associated with each wheeling transaction is a more realistic measure of the actual use of transmission network [13], so it was widely used into the wheeling cost calculation.

Minimize $C_w = \sum_{k=1}^{L} \left(C_{lk} \cdot \sum_{i=1}^{N} P_{lk}^i \right)$ (6)

Where

C_w: Total wheeling cost;

C_{lk}: Unit cost of *k*th transmission line;

P_{lk}^i: Load at the *k*th line caused by generator *i*;

P_{lk}^i can be calculated using the Bialek's tracing method [2,14], which is assumed that nodal inflows are shared proportionally among nodal outflows. In the tracing method, it uses a topological distribution factor to determine the contribution of individual generators or loads to every line flow. Assumed the net power flow as positive direction, a particular transaction can flows in the opposite direction of the net flow, which called counter flow. The topological distribution factors calculated in the tracing method are always positive, that means the line power traced to each generator are positive, therefore this method can eliminates counter flow problem easily.

2.2.3 Maximization reliability

After RCOPF calculation for a set of generator outputs, it is possible to calculate the reliability index from the equation (1).

2.3 RCOPF constraints

2.3.1 Power balance constraints

As a basic obligation of traditional OPF, the total power generation must be equal to the total power demand and power losses in the transmission system:

$$\sum_{i=1}^{N} P_{Gi} - P_{Demand} - P_{Loss} = 0 \quad (7)$$

2.3.2 Generation limit constraints

For the safety operation of a generator, power output from each generator must be within a limit:

$$P_{Gi}^{MIN} \le P_{Gi} \le P_{Gi}^{MAX} \quad (8)$$

2.3.3 Line capacity constraints

The every line flow should be below the permissible value to ensure the system security:

$$P_{lk} \le \lambda_{lk} \cdot \overline{P_{lk}} \quad (9)$$

λ_{lk}: Permissible line *lk* overloaded percentage.

2.3.4 Emission limits constraint

The total pollution generated in an area must be below the specified limit *MS*:

$$\sum_{i=1}^{N} Q_{Gi} \le MS \quad (10)$$

Where

$Q_{Gi} = a + b \cdot P_{Gi} + c \cdot P_{Gi}^2 + d \cdot \exp(e \cdot P_{Gi})$: Emission of the *i*th generator, Ton/h;

a, b, c, d, e: Coefficients of the *i* th generator emission;

MS: Maximum air pollution allowance for a particular area.

3 Implementation of MOGA

Genetic algorithms are general purposed techniques for optimisation and learning, and especially suitable for this multi-modal, multi-objective, highly non-linear, discontinuous problem [3,7]. The implementation of MOGA is realised using the concept of Pareto Optimality. This uses the idea that a solution x is "better" than a solution y if x dominates y. In natural language, x dominates y if x is better than y for at least one objective function, and is no worse for any of the others. A solution is Pareto-optimal if it is not dominated by any other solution. This concept is very powerful for a small number of objectives, however, when the number of objectives grows large, it can be very inefficient. In order to improve the efficiency of MOGA, this paper modifies the original concept slightly so that x is "better" than a solution y if more objectives in x are better than that of y.

Pareto optimality has been implemented by using *Tournament Selection*. During the reproduction stage the population is randomly divided up into pairs of candidate solutions. Each pair of candidate solutions is a tournament. If one candidate solution betters its competitor it is declared the winner and is copied. Its copy then replaces the loser in the post-reproduction population.

The implementation procedure of MOGA is shown in figure 1. Due to the nature of Pareto optimality, more than one candidate solution may be optimal. For example, one candidate solution may have a low cost but high emission and another may have a high cost but low emission. It is common to find many "non-dominated" and hence Pareto optimal solutions in the course of optimisation.

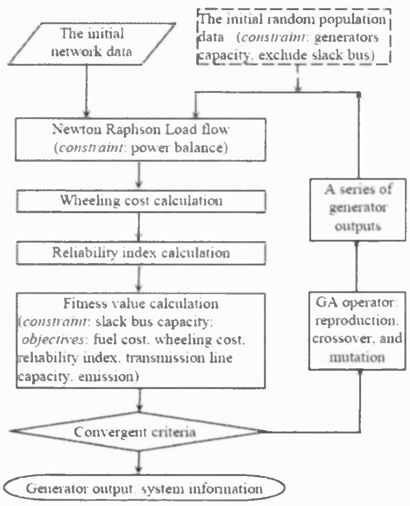

Figure 1: RCOPF using MOGA

4 Case study

4.1 Test system

The proposed algorithm is tested on the standard IEEE-30-bus test system, which is showed in Figure 2 [11]. The bus data, branch data, generator fuel cost and emission coefficients are given in references [11,12,16], respectively.

The parameters for the GA are set as:
Population size: 100
Crossover probability: 0.9
Mutation rate: 0.01
Total generation time: 100

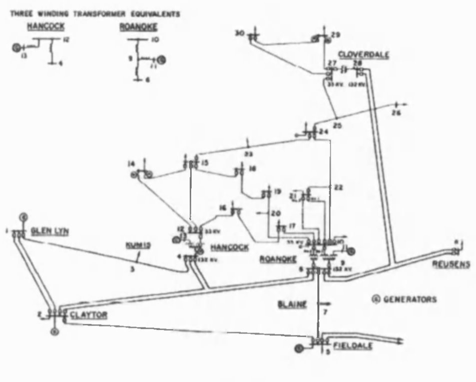

Figure 2: IEEE 30-bus test system

4.2 Simulation result

Figure 3 shows 50 non-dominant solutions from MOGA in the 3D coordinates, the three axes are emission, reliability preference index, and cost made up of fuel and wheeling cost. All 50 solutions have their own strength and weakness. Table 1 and 2 show the results taken from the point (0.025, 0.209, 640.73) marked by O, where table 1 gives the generation data and table 2 presents line flow data.

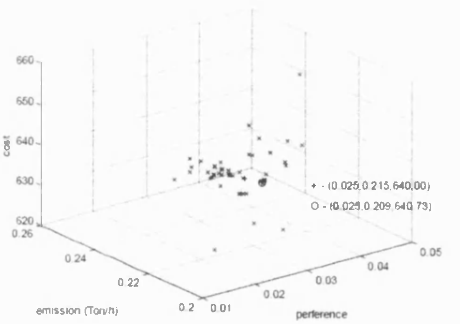

Figure 3: 50 times MOGA simulation results

No.	*Output (MW)*	*Fuel Cost($/h)*	*Wheeling cost ($/h)*	*Emission (Ton/h)*
G1	51.12	138.37	3.5681	0.03
G2	38.23	84.87	2.6152	0.01
G5	66.13	156.52	0.0	0.03
G8	76.45	121.52	1.8699	0.06
G11	25.00	67.50	0.4826	0.03
G13	29.52	62.99	0.4232	0.05
Total	286.45	631.77	8.959	0.21

Table 1: Generators data

No.	i(from)	j(to)	Pij (MW)	Qij (MVA)
1	1	2	32.0421	17.8373
2	1	3	19.0763	14.1283
3	2	4	11.5559	9.1552
4	3	4	16.4216	16.4388
5	2	5	24.6138	9.6711
6	2	6	12.1488	11.7409
7	4	6	2.8709	11.3973
8	5	7	-3.7820	5.7974
9	6	7	26.7984	1.9548
10	6	8	-36.6081	17.6636
11	6	9	8.0768	-14.1232
12	6	10	9.5655	-1.8988
13	9	11	-25.0000	-19.6942
14	9	10	33.0768	16.7779
15	4	12	17.3020	-14.9299
16	12	13	-29.5161	-12.2919
17	12	14	8.3470	3.1973
18	12	15	19.2010	10.1657
19	12	16	8.0701	6.9559
20	14	15	2.0585	1.4133
21	16	17	4.4735	4.9528
22	15	18	606277	3.4147
23	18	19	3.3714	2.4002
24	19	20	-6.1393	-1.0213
25	10	20	8.4186	1.8954
26	10	17	4.550	0.9448
27	10	21	16.0677	9.7547
28	10	22	7.8007	4.4281
29	21	22	-1.5497	-1.6976
30	15	23	6.1376	5.0984
1	22	24	6.1949	2.6144
2	23	24	2.8775	3.3771
3	24	25	0.2964	-0.8394
4	25	26	3.5460	2.3687
5	25	27	-3.2511	-3.2107
6	28	27	16.5619	-0.9341
7	27	29	6.1927	1.6740
8	27	30	7.0955	1.6692
9	29	30	3.7045	0.6075
10	8	28	9.6484	-3.9890
11	6	28	6.9898	6.3752

Table 2: Line flow results

Figures 4~6 demonstrate emission, reliability index, cost of each solution from figure 3.

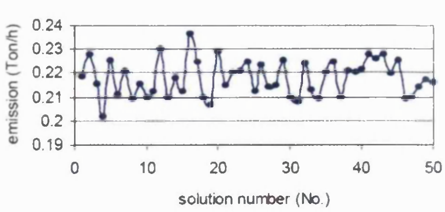

Figure 4: Emission profile

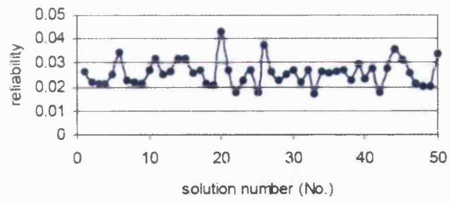

Figure 5: Reliability index profile

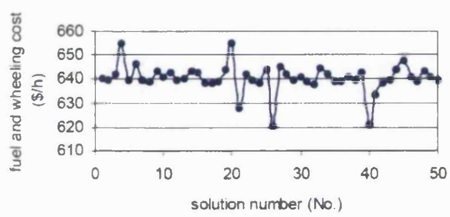

Figure 6: Fuel and wheeling cost profile

5 Conclusion

This paper presents an improved OPF framework. Firstly, this paper presents a more realistic OPF problem formulation by incorporating the reliability index, transmission cost and environmental limits into the traditional OPF. Secondly, the paper developed a multi-objective genetic algorithm to effectively handle the multi-objective, multi-constraints model with very high performance. The concept of Pareto Optimality is adopted to handle the multiple objectives. The results are a set of non-dominate solutions that have different qualities against the five objectives. These assessments provide useful information for power engineers to make sensible compromising decisions.

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Development of a Novel MW+MVAr-Miles Charging Methodology

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***Abstract*—This paper describes the principle and implementation of a new MM+MVAr-Miles based charging methodology to allocate the existing distribution network's annuity cost. The proposed charging methodology separates network facilities' cost due to the respective real and reactive power flows. The costs are then allocated to network users according to their nature (demand or generation) and their power factors. The charging methodology is developed with an aim of reflecting the true cost and benefit of network customers, especially of embedded generators (DGs). The charging method is demonstrated on a subset of a practical distribution network, its effectiveness is shown through the comparison with MW-Mile and MVA-Mile charging methodologies. This paper results from work undertaken in a project on distribution charging methodologies for Western Power Distribution. The views in the paper expressed are not those of Western Power Distribution.**

***Index Terms*—Distribution network, network charging methodologies, embedded generators.**

I. Introduction

Existing network charging or embedded charging can be defined as the revenue that has to be allocated among all the connected demand/generation customers to meet the annual cost of all the existing facilities, due to their contribution to network depreciation [1]. Typically, their charges are driven by their demand over peak periods.

All demand/generation customers of a distribution network are required to contribute a percentage from the existing network charging and the rest from the long-run cost. Traditionally, the embedded cost of a distribution network is very small when compared with incremental cost, based on the planning procedure that the new customers who caused additional system reinforcement have to pay for the network incremental cost. This leads to distribution network charging mainly based on long run cost. However, in the UK, this so called Deep Different methods have been used for allocating existing network charging like postage stamp and contract path [2-3], both are not considering the effect of actual loading on multiple circuits due to a transaction. The Boundary Flow method [1] and the MW-Mile method [4] have improved upon the limitations of the first two methods by respecting power flows on multiple paths due to a customer. However, these methods do not consider the extent of the use of network from reactive power flows. This use of network due to a customer's poor power factor can be significant in a distribution network. As a result, MVA-Mile method [4-5] is proposed to take into account of the true extent of the use of the network by considering both active and reactive power. The MVA-Mile method however treats both real and reactive power the same, fails to differentiate reactive power injection and dawn within a facility. This leads to the new MW+MVAr-Mile charging methodology that is able to accurately account for the extent of the use of network for a customer, taking into account of their respective MW and MVAr power flow from the source to the customer. By separating the MW and MVAr power flows. the proposed charging methodology acknowledges the full cost-benefit of network users, especially embedded generators. The principle of the proposed method is demonstrated on a subset of 132kv distribution network. its effectiveness is clearly shown through the comparison with MW-mile and MVA-mile methodologies.

II. Mathematical Formulation

This section gives mathematical formulation for all three use of system charging methodologies, namely MW-Mile, MVA-Mile and the newly proposed MW+MVAr-Mile methodologies.

For a given distribution network, facility f's cost is assumed to be DFC_f, the annual fixed rate of return is assumed to be $AFRR_f$ for the year under study, then the annual revenue requirement (ARR) for each facility can be determined with the following equations:

$$ARR_f = AFRR_f \times DFC_f \tag{1}$$

A) *MW-Mile Method*

For the MW-Mile (MWM) method, existing network costs of distribution system are allocated proportionally to the MW flows caused by a customer in a network. If the MW flows in each distribution facility f caused by customer T is $(MW_f)_T$, the network charges Cc_T for customer T is given by the following equation.

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$$Cc_T = \frac{\sum_f (MW_f)_T L_f}{\sum_T(\sum_f (MW_f)_T L_f)} \times C \qquad (2)$$

where

C= Total annual revenue requirement per hour £/h

$C = \sum_f C_f$ £/h

$(MW_f)_T$ = MW flow in facility f due to customer T.

L_f = Length of facility f

B) MVA -Mile Method

It has been recognized that the use of distribution network has been best measured by monitoring both real and reactive power flow. This is because of a circuit rating based on its MVA ratings, its reactive power components can be as significant as real power when power factor is poor. This leads to the development of MVA-Mile charging methodology, which requires ac power flows to allocate network charges when considering both active and reactive power flow. In this charging regime, the MVA flows due to customer T is first established, the cost allocation to custom T is subsequently given by the following equation:

$$Cc_T = \frac{\sum_f (MVA_f)_T L_f}{\sum_T(\sum_f (MVA_f)_T L_f)} \times C \qquad (3)$$

where

$(MVA_f)_T$ = MVA flow in facility f due to customer T.

C) MW+MVAr -Mile Method

Even though the MVA-Mile method has provided better measurement for the extent of the use of the network by monitoring both real and reactive power flow within the facilities, it cannot distinguish if a custom drawing or injecting reactive power, hence, customers helping the system can be unfairly treated. This leads to the formulation of MW+MVAR-Mile method.

D) Economic Principle of MW+MVAr -Mile Method

For a circuit f, the relationship between the apparent power flow S and its real and reactive power contribution is shown in Figure 1.

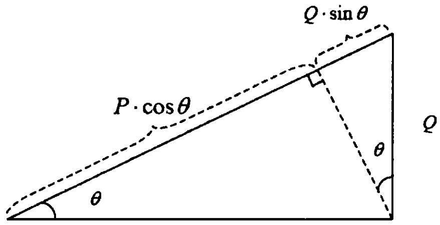

Fig. 1: Contribution of real and reactive power to apparent power

From the above diagram, the magnitude of apparent power S for the circuit f can be described as:

$$S_f = P_f \cdot \cos\theta_f + Q_f \cdot \sin\theta_f \qquad (4)$$

Hence, if the annualized circuit cost associated with S_f is C_f, then the extent of the use of the circuit due to real power can be determined by:

$$Cp_f = \frac{P \cdot \cos\theta}{S_f} \times C_f \qquad (5)$$

where C_{pf} is the extent of the network cost due to the circuit real power flow.

This leads to the contribution due to real power as:

$$C_{P,f} = \cos\theta^2 \times C_f \qquad (6)$$

Therefore, the total cost due to network's real power flows is:

$$C_p = \sum_f C_{P,f} \qquad (7)$$

While the extent of the use of network due to reactive power is formulated as:

$$C_{Q,f} = (1 - \cos\theta^2) \times C_f \qquad (8)$$

This leads to the total cost due to network's reactive powers:

$$C_Q = \sum_f C_{Q,f} \qquad (9)$$

where $C = C_P + C_Q$ (10)

Once the network cost due to real and reactive power is separated, the total cost for customer T from its real and reactive power flows over network circuits is:

$$Cc_T = \frac{\sum_f (MW_f)_T L_f}{\sum_T(\sum_f (MW_f)_T L_f)} \times C_P + \frac{\sum_f (MVAr_f)_T L_f}{\sum_T(\sum_f (MVAr_f) L_f)} \times C_Q \qquad (11)$$

III. Results and discussions

The section illustrates the proposed MW+MVAr-Mile methodology on a small system. The effectiveness of the proposed charging method is demonstrated through the comparison with MW-Mile and MVA-Mile methodologies.

The test system is an 8 busbar subset of the practical Western Power Distribution network at 132KV voltage level. For demonstration purpose, the study illustrates the proposed charging principle by only allocating facility L_f cost to customers at bus 2 according to their extent of the use of the circuit, while the rest of 7 buses are lumped into one load taken from bus 1, as shown in Figure 1.

The comparison between different methodologies are carried out on the following four test cases.

A) Case 1

Case 1 forms the base case that only one load customer is connected to bus 2 as shown in Figure 1, where the charges are laid to customers based on the extent of the use of circuit L_f by the load customers. Demand customer 1 has a power factor of 0.77, while customer 2 has a power factor of 0.62. The annualized cost of the circuit L_f is £236760/year.

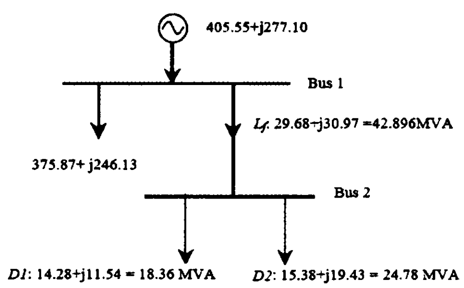

Figure 2. A base load flow on the reduced 2-busbar system.

Table I presents network charges for the two demand customers at bus 2 with all three charging methodologies. The table clearly shows that the MW-mile method does not distinguish the differences of two customer's power factor, simply assigns the circuit cost according to the real power flow. Where both MVA-Mile and MW+MVAr-Mile methods acknowledge the poorer power factor of customer 2, hence accordingly penalize the customer. Due to the similar nature of the two demands, the MW+MVAr-Mile method agrees well with that of MVA-Mile method, slight difference lies in MVA-Mile method treats real and reactive power the same, while MW+MVAr takes their respective true contribution to the circuit power flow.

TABLE I. USE OF NETWORK CHARGES FOR BUS 2 CUSTOMERS

Charging methodologies	Demand 1	Demand 2
MW-Mile C=£236760/year	£0.9112/MW/h	£0.9112/MWh
MVA-Mile C=£236760/year	£0.6251/MVA/h	£0.6251/MVA/h
MW+MVAr-Mile	£0.6252/MVA/h	£0.6274/MVA/h
Cp_1 = £113347/year (Cost due to MW flow)	0.4363	58.775
C_{QJ} = £123413/year (Cost due to MVAr flow)	0.4549	77.427

B) Case 2

The difference between MW+MVAr-mile and MVA-Mile charging methodologies becomes apparent when embedded generators comes into play. To better demonstrate the benefit of the proposed charging methodology, an embedded wind generator is introduced at bus 2, while demand customers are grouped to one demand D. In this case, the generator's power output at the time of system peak is: 20-j20. Figure 3 shows the load flows when the generator is connected.

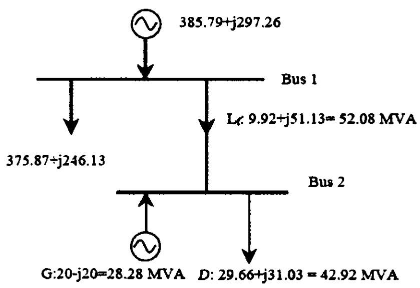

Figure 3. Power flows on the reduced 2-busbar system. the embedded generator output - 20-j20.

From the load flow results it has been found that the real power drawn by the demand customers has been reduced due to the injection caused by the generator, shown by the reduced real power flow on the line. But the loading of the connected facilities have increased by 21% due to reactive power drawn by the same generator. Table II gives the charges to both generation and demand customers with three charging methods.

TABLE II. USE OF NETWORK CHARGES FOR BUS 2 CUSTOMERS. WHERE DEMAND DOMINATING L_f'S REAL POWER FLOW. BOTH GENERATION AND DEMAND CONTRIBUTING TO LINE'S REACTIVE POWER FLOW

Charging methodologies	Generation (£/year)	Demand (£/year)
MW-Mile C=£236760/year	0	236,760
MVA-Mile C=£236760/year	94,038	142,722
MW+MVAr-Mile	89,434	147,326
Cp_1 = £8568/year (Cost due to MW flow)	0	8.568
C_{QJ} = £228192/year (MVAr) (Cost due to MVAr flow)	89.434	138.758

When the MW-Mile methodology is adopted here, the cost due to the reactive power will be lost, leading to a favorable assessment for embedded generators. While the MVA-Mile methodology will ignore the real power contribution from the generator, network will charges for its 20MW power injection, despite the power has been immediately consumed by its neighbour demand customer and has reduced net power flow of the circuit from the original 29.68 MW to 9.92 MW. This gives poor assessment of contribution from embedded generator.

In comparison, the proposed MW+MVAr is able to respect both cost and benefit of network users, especially embedded generators. Since embedded generator does not use the network facility to transport its real power, hence, no charges has been assigned to the generation customer for its real power provision, however, it uses the network to draw reactive power. As a result, the generator will be charged for its use of the circuit to draw reactive power. charges is allocated depends on its share of contribution to the reactive power flow of the circuit.

Although the difference between MVA-Mile and MW+MVAr-Mile methods are small in this case, still the latter reflect the true extent of the use of the network by only charging the embedded generator for its reactive power draw from the network while MVA-Mile method also charges for its power injection.

C) Case 3

Similarly when the generator has operated with its maximum generation of 80MW, the loading of the connected facilities have increased by 40% due to both generator's real power injection and reactive power drawn, as shown in Figure 4. So a charging methodology for both the generator and demand customers have been assigned based on their real and reactive power drawn/injection. Here, no cost has been assigned to the demand customer because it has not used the network to draw its real power.

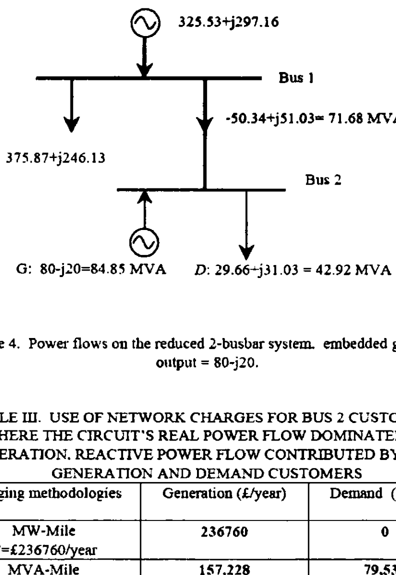

Figure 4. Power flows on the reduced 2-busbar system. embedded generator output = 80-j20.

TABLE III. USE OF NETWORK CHARGES FOR BUS 2 CUSTOMERS, WHERE THE CIRCUIT'S REAL POWER FLOW DOMINATED BY GENERATION, REACTIVE POWER FLOW CONTRIBUTED BY BOTH GENERATION AND DEMAND CUSTOMERS

Charging methodologies	Generation (£/year)	Demand (£/year)
MW-Mile C=£236760/year	236760	0
MVA-Mile C=£236760/year	157,228	79,532
MW+MVAr-Mile	162,032	74,728
Cp_J = £113867/year (Cost due to MW flow)	113.867	0
C_{QJ} = £122898/year (Cost due to MVAr flow)	48.165	74.728

D) Case 4

Finally when the generator is operated with 20MW and 20MVAR injection, then the generator supports the demand customer at that point for both real and reactive power requirement. As a result, the complete facility cost has been assigned to the demand customer only and presented in the Table IV.

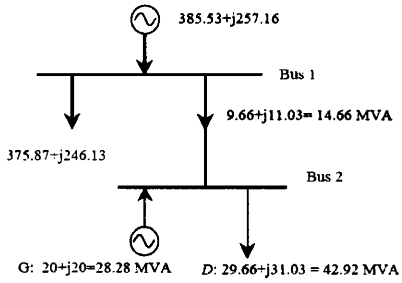

Figure 5. Power flows on the reduced 2-busbar system with embedded generator output as 20+j20.

TABLE IV. USE OF NETWORK CHARGES FOR BUS 2 CUSTOMERS, WHERE THE CIRCUIT FLOW DOMINATED BY THE DEMAND CUSTOMER

Charging methodologies	Generation (£/year)	Demand (£/year)
MW-Mile C=£236760/year	0	236,760
MVA-Mile C=£236760/year	94038	142,722
MW-MVAr-Mile	0	236,760
Cp_J = £104034/year	0	104,034
C_{QJ} = £132726/year	0	132,726

VI Conclusions

The paper proposed a new MW+MVAr-Mile charging methodology to allocate the embedded cost based on network users' extent of the use of network facilities. The advantages of this technique over existing MW-Mile and MVA-Mile methodologies lie in its ability to appropriate account for customers' cost and benefit, especially for embedded generators. This ability has been demonstrated over four test cases. While the MW-Mile method neglects customers' poor power factors, MVA-Mile and MW+MVAr-Mile methodologies will reward customers with good power factor and penalize those with poor power factors. For customer with similar characteristics, MVA-Mile and MW+MVAr-Mile give comparable results. However, when embedded generators come into play, MVA-Mile method cannot distinguish between generator injecting and drawing reactive power from the network, while MW+MVAr-Mile can give a full assessment of generators or demands contribution to the network. The proposed MW+MVAr-Mile methodology is although demonstrated on a distribution network, is equally applicable to transmission network where the extra computational burden is justifiable.

IV. Refeferences

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V. Biographies

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Ji Wang (Student M'2004) was born in Henan province in China, on November 24, 1978. He received the BEng in Electrical Power System & Automation at University of Zhengzhou, China, in 2001, and the MSc in Electrical Power with Merit at University of Newcastle upon Tyne, U.K., in 2003. Currently, he is pursuing the PhD in the area of network charging methodologies.

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MW+MVAr-Miles Based Distribution Charging Methodology

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***Abstract*—This paper describes the principle and implementation of a new MW+MVAr-Miles based charging methodology for pricing distribution networks. The charging methodology was developed with an aim of reflecting the true cost and benefit of network users, especially embedded generators (EGs). The proposed charging methodology respects the cost to a network due to both real and reactive power, i.e. power factor of network users. In addition, the charging model can differentiate directions of real and reactive power flow of a network user, for example, wind generation provides real power and absorbs reactive power. This differentiation allows the cost and benefit to the network of a network user being properly accounted for. The charging method is demonstrated on an two-busbar system, derived from a practical distribution network. Its effectiveness is demonstrated through the comparison with MW-Mile and MVA-Mile charging methodologies.**

***Index Terms*—Distribution network, network charging methodologies, embedded generators.**

I. INTRODUCTION

THE electrical power supply industry around the world has experienced a period of rapid and critical changes. regarding the way electricity is generated, transmitted and distributed. The need for more efficiency in power production and delivery has led to privatization, restructuring and finally deregulation of the power sectors in several countries traditionally under control of federal and state governments. Many countries like Latin America and Chile during 1980. England and Wales during 1989. Argentina during 1992. Europe during 1996 have undergone the process of competitive electricity market. resulting in seperate Transmission. Distribution and Generation companies from a monopoly structure[11,14]. Though there are some pitfalls. the end users of the deregulated system are enjoying the fruits of the deregulated electricity industry tree. Transmission and distribution are still considered natural monopolies that require regulations to achieve fair competition and also to ensure open. nondiscriminatory access to all network users. especially small embedded generators [13,15,17].

Distribution network charges are charges against generator. large industrial customers and suppliers for their use of a distribution network. The charges are set to reflect the cost of installation, operation and maintenance of the distribution network[18,19].

The current distribution reinforcement model[5,7,21] adopted by majority of distribution network operators (DNOs) in the UK is based on 500MW reinforcement model. It is essentially a post-stage stamp charging methodology across the same voltage level.

The charging methodology is under close scrutiny by the regulator – OFGEM (Office of Gas and Electricity Market). primarily driven by the following two major concerns:

1) Inability in providing locational signals for the siting of future generation and demand
2) Inability to facilitate the potentially significant increases in embedded generation.

As an alternative distribution charging methodologies. MW-miles methodology [3] has the advantage of acknowledge the extensiveness of the use of a network by network users, but fails to respect the cost/benefit to the network due to reactive power. A charging method based on DC power flow[1] will inevitably introduce errors in reflecting true cost to a network. This is particularly problematic for embedded wind generators, where they tend to inject real power and withdraw reactive power. As a result. if only DC power flow is considered in a charging model. it will credit embedded generator's active power contribution[8], but fail to penalise its reactive power drawn. This can result in misleading locational signals. hence. economic inefficient network charging methodologies[4,20].

MVA-Miles method is an enhanced charging methodology over MW-Miles. it considers the extensiveness of the use of the network by network users due to their active and reactive power injection/drawn. The MVA-Miles method however cannot distinguish the direction of real and reactive power flow. The methods work well for demand and generation where they either withdrawn both real and reactive power or inject both. However, In the case of wind generator injecting real power and withdrawing reactive power. the MVA-Miles method fails to distinguish the difference in the direction of the same network user. resulting in misleading network

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1-4244-0493-2/06/$20.00 ©2006 IEEE.

charges[25-28].

In this paper, a new MW+MVAr-Mile charging methodology has been introduced that not only respects the power factor of network users but also the leading or lagging nature of power factor. By separating the MW and MVAr power flows, the proposed charging methodology acknowledges the full cost-benefit of network users, especially embedded generators[9,14]. The principle of the proposed methodology is shown on two busbar system and validated through the comparison with the MW-Miles and MVA-Miles methodologies.

II. Mathematical Formulation

This section firstly gives mathematical formulation for MW-Miles and MVA-Miles methodologies and secondly, introduces the newly proposed MW+MVAr-Miles methodology.

For a given distribution network, a network component *f*'s cost is assumed to be DFC_f, the annual fixed rate of return is assumed to be $AFRR_f$ for the year under study, then the annuity cost (*AN*) for each component can be determined with the following equations:

$$AU_f = AFRR_f \times DFC_f \qquad (1)$$

A) MW-Mile Method

For the MW-Mile (MWM) method, existing network costs of distribution system are allocated proportionally to the MW flows caused by a customer in a network[16]. If the MW flows in each distribution component *f* caused by customer *T* is $(MW_f)_T$, the network charges Cc_T for customer *T* is given by the following equation.

$$Cc_T = \frac{\sum_f (MW_f)_T L_f}{\sum_T (\sum_f (MW_f)_T L_f)} \times C \quad \text{£/year} \qquad (2)$$

and $C = \sum_f C_f$ £/year

where

C: Total annual revenue requirement per hour £/h

$(MW_f)_T$. MW flow in component *f* due to customer *T*.

L_f. Length of network component *f*

B) MVA -Mile Method

It has been recognized that the cost to a distribution network is best measured by monitoring both real and reactive power flow. The MVA-Mile charging methodology takes account of customers' power factor as well as the extensiveness of the use of a network. In this charging regime, the MVA flows due to customer *T* is first established, the cost allocation to custom *T* is subsequently given by the following equation:

$$Cc_T = \frac{\sum_f (MVA_f)_T L_f}{\sum_T (\sum_f (MVA_f)_T L_f)} \times C \qquad (3)$$

$$MVA_f = \sqrt{P_f^{\,2} + Q_f^{\,2}} \qquad (4)$$

where

$(MVA_f)_T$. *MVA* flow in network component f due to customer *T*.

P_f. Real power flow in network component f

Q_f. Reactive power flow in network component f

C) MW+MVAr -Mile Method

This new charging model is to reflect three characteristics of a customer: the extensiveness of the use of a network, its power factor and the leading/lagging nature of the power factor. Compared with the MVA-Miles methodology, the model has the additional capability of reflecting the differences in directions of real and reactive power flow, thereby is able to reflect the full cost-benefit of a customer, especially embedded generators.

D) Principle of MW+MVAr -Miles Methodology

For a network component *f*, the relationship between the apparent power flow *S* and its real and reactive power contribution is commonly represented by equation (4). Since it cannot distinguish the direction of power flow, this paper developed a linear relationship between apparent power and its real and reactive power counterparts, shown below:

$$S_f = P_f \cdot \cos\theta_f + Q_f \cdot \sin\theta_f \qquad (5)$$

Hence, if the annualized circuit cost associated with S_f is C_f, then the extent of the use of the circuit due to real power can be determined by:

$$Cp_f = \frac{P \cdot \cos\theta}{S_f} \times C_f \qquad (5)$$

where C_{pf} is the extent of the network cost due to the circuit real power flow.

Since S_f can also be represented by:

$$S_f = \frac{P}{\cos\theta} \qquad (6)$$

Substitute Equation (6) to (5), leads to:

$$C_{P,f} = \frac{P \cdot \cos\theta}{\dfrac{P}{\cos\theta}} \times C_f = \cos\theta^2 \times C_f \qquad (7)$$

Therefore, the total cost due to network's real power flows is:

$$C_p = \sum_f C_{P,f} \qquad (8)$$

While the extent of the use of network due to reactive power is formulated as:

$$C_{Q,f} = \frac{Q\cdot\sin\theta}{\frac{Q}{\sin\theta}}\times C_f = \sin\theta^2 \times C_f = (1-\cos\theta^2)\times C_f \tag{9}$$

This leads to the total cost due to network's reactive powers:

$$C_Q = \sum_f C_{Q,f} \tag{10}$$

where $C = C_P + C_Q$ (11)

Once the network cost due to real and reactive power is separated. the total cost for customer T from its real and reactive power flows over all network components is:

$$Cc_T = \frac{\sum_f (MW_f)_T L_f}{\sum_T(\sum_f (MW_f)_T L_f)}\times C_P + \frac{\sum_f (MVAr_f)_T L_f}{\sum_T(\sum_f (MVAr_f) L_f)}\times C_Q \tag{12}$$

III. Results and discussions

The section illustrates the proposed MW+MVAr-Mile methodology on a simple test system. The effectiveness of the proposed charging method is demonstrated through the comparison with DRM. MW-Miles and MVA-Miles methodologies.

The test system is a subset of the practical Western Power Distribution network with loads connected to buses at 132KV voltage level. The study illustrates the proposed charging principle by allocating network asset L_f cost to bus 2 customers and bulk customer according to their extent of the use of the circuit. The annuity cost of circuit L_f is £236760/yr. supporting 90MVA power flow. The basic diagram is shown in Figure 1.

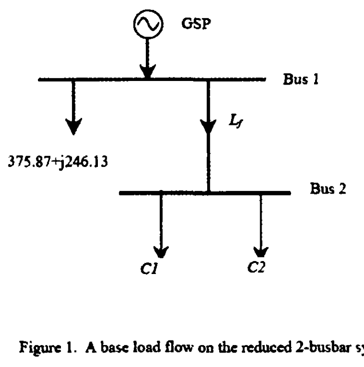

Figure 1. A base load flow on the reduced 2-busbar system.

Two test cases were derived representing changes in customer nature of bus 2 customers: (1) demand users only: (2) demand and generator users. where the generator reduces the circuit's real power flow but increases its reactive power flow. this is shown in Table I.

TABLE I CUSTOMER CHARACTERISTICS WITH DIFFERENT CASE STUDIES

	Customer 1	Customer 2	Power flow over L_f
Case 1	14.28+j11.54	15.38+j19.43	29.68+j30.97=42.896MVA
Case 2	-20+j20	29.66+j31.03	9.92+j51.13= 52.08 MVA

A) Case 1

Case 1 forms the base case that only demand customers were connected to bus 2. where the charges are laid to customers based on the extent of the use of circuit L_f by the load customers. Demand customer 1 has a power factor of 0.77. while customer 2 has a power factor of 0.62.

Table II presents network charges for the two demand customers at bus 2 with all three charging methodologies. The table clearly shows that the MW-mile method does not distinguish the differences of two customer's power factor. simply assigns the circuit cost according to the real power flow. Where both MVA-Mile and MW+MVAr-Mile methods acknowledge the poorer power factor of customer 2. hence accordingly penalize the customer. Due to the similar nature of the two demands. the MW+MVAr-Mile method agrees well with that of MVA-Mile method. slight difference lies in MVA-Mile method treats real and reactive power the same, while MW+MVAr takes their respective true contribution to the circuit power flow.

TABLE II. USE OF NETWORK CHARGES FOR BUS 2 CUSTOMERS

Charging models	Demand charges (£/year)	Generation charges (£/year)	Un-recovered revenue	Un-recovered revenue (unit price)
MW-Mile	77,763	0	159,000	392 £/MW/yr
MVA-Mile	113,490	0	123,270	£250 £/MVA/yr
MW+MVAr-Mile	111,310 MW: 46.041 MVAr: 65.271	0	125,450	£254 £/MVA/yr

B) Case 2

The difference between MW+MVAr-mile and MVA-Mile charging methodologies becomes apparent when embedded generators came into play. To better demonstrate the benefit of the proposed charging methodology. an embedded wind generator was introduced at bus 2. while demand customers were grouped to one demand D. In this case. the generator's power output at the time of system peak is: 20-j20.

From the load flow results it has been found that the real power drawn by the demand customers were reduced due to the injection caused by the generator. But the loading of the connected assets have increased by 21% due to reactive power drawn by the same generator. Table III gives the charges to both generation and demand customers with three charging methods.

TABLE III. USE OF NETWORK CHARGES FOR BUS 2 CUSTOMERS. WHERE DEMAND DOMINATING L_f'S REAL POWER FLOW. BOTH GENERATION AND DEMAND CONTRIBUTING TO LINE'S REACTIVE POWER FLOW

Charging models	Demand charges (£/year)	Generation charges (£/year)	Un-recovered revenue	Un-recovered revenue (unit price)
MW-Mile	**77,763**	**-52613**	**211,612**	**521.8 £/MW/yr**
MVA-Mile	**113,490**	**-74395**	**197,670**	**£401 £/MVA/yr**
MW+MVAr-Mile	**94,799**	**41,501**	**125,450**	**£254 £/MVA/yr**
	MW: 46.041	MW: -10.022		
	MVAr: 65,271	MVAR: 51,522		

When the MW-Mile methodology is adopted here. the cost due to the reactive power will be lost. leading to a favorable assessment for embedded generators. While the MVA-Mile methodology will ignore the real power contribution from the generator. network will charges for its 20MW power injection. despite the power has been immediately consumed by its neighbour demand customer and has reduced net power flow of the circuit from the original 29.68 MW to 9.92 MW. This gives poor assessment of contribution from embedded generator.

In comparison. the proposed MW+MVAr is able to respect both cost and benefit of network users. especially embedded generators. Since embedded generator does not use the network facility to transport its real power. hence. no charges has been assigned to the generation customer for its real power provision. however. it uses the network to draw reactive power. As a result. the generator will be charged for its use of the circuit to draw reactive power. charges is allocated depends on its share of contribution to the reactive power flow of the circuit.

VI CONCLUSIONS

The paper demonstrates the newly proposed MW+MVAr-Mile charging methodology to allocate the network cost based on network users' extent of the use of network facilities. The advantages of this technique over existing MW-Mile and MVA-Mile methodologies lie in its ability to appropriate account for customers' cost and benefit. especially for embedded generators. While the MW-Mile method neglects customers' poor power factors, MVA-Mile and MW+MVAr-Mile methodologies will reward customers with good power factor and penalize those with poor power factors. For customer with similar characteristics. MVA-Mile and MW+MVAr-Mile give comparable results. However. when embedded generators come into play. MVA-Mile method cannot distinguish between generator injecting and drawing reactive power from the network. while MW+MVAr-Mile can give a full assessment of generators or demands contribution to the network. The proposed MW+MVAr-Mile methodology is although demonstrated on a distribution network. is equally applicable to transmission network where the extra computational burden is justifiable.

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